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COST-EFFECTIVENESS OF A UNIFORM NATIONAL SULFUR EMISSIONS TAX

Tayler H. Bingham, et al

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The study's main objectives are (1) to calculate the relationship between specified levels of a uniform national sulfur emissions tax, and the resulting reduction in projected emissions from primary stationary source emitters; (2) to estimate the costs of emission-reduction activities that ensue as a consequence of a given emission-tax level; and (3) to determine the tax revenue generated in light of alternative emission tax levels, and hence the total gross environmental costs imposed on sulfur emitters.

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This project was under the direct supervision of Tayler H. Bingham with several individuals contributing to specific aspects of the research described in this report. Principal among these and their contributions are:

Philip C. Cooley	Model design and programming
Mark E. Fogel	Control costs and new technology options
Donald R. Johnston	Analysis of impact of tax on air quality
David A. LeSourd	Area source analysis
Allen K. Miedema	New technology analysis
Richard E. Paddock	Steam-electric power plant and sulfuric acid plant control costs
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TABLE OF CONTENTS

Chapter Page

1: INTRODUCTION AND SUMMARY 1
  1.1 Background 1
  1.2 Effects of Sulfur Oxides 2
  1.3 The Concept of a Tax on Sulfur Emissions 3
  1.4 Approach 3
  1.5 Assumptions, Limitations, and Capabilities 6
  1.6 Summary of Findings 8
2: THE APPLICATION OF EMISSIONS TAXES FOR POLLUTION CONTROL 11
  2.1 Introduction 11
  2.2 Air Quality and Market Failure 11
  2.3 Emissions Taxes 12
3: ANALYSIS OF THE EFFECTIVENESS AND COSTS OF A TAX ON SULFUR EMISSIONS 15
  3.1 Introduction 15
  3.2 The Emissions Response Model 15
    3.2.1 Fuel Combustion Sources 16
      3.2.1.1 Fuel Supplies and Prices 16
        3.2.1.1.1 Fuel Supplies 16
        3.2.1.1.2 Fuel Price Adjustment 18
      3.2.1.2 Steam-Electric Power Plants 18
      3.2.1.3 Area Sources 19
    3.2.2 Industrial Process Sources 21
      3.2.2.1 Petroleum Refineries 22
      3.2.2.2 Sulfuric Acid Plants 23
      3.2.2.3 Primary Nonferrous Smelters 23

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Chapter Page

3.3 Cost of Control Functions 24

3.4 Effectiveness 25

3.5 Costs 29

3.6 Tax Revenues 30

3.7 Cost-Benefit Analysis 30

3.8 Impacts on Consumer Prices 31

4: SOURCE-BY-SOURCE ANALYSIS OF THE EFFECTIVENESS AND COSTS OF A TAX ON SULFUR EMISSIONS 37

4.1 Introduction 37

4.2 Steam-Electric Power Plants 37

4.2.1 Background 38

4.2.2 Industry Growth 38

4.2.3 Effectiveness 38

4.2.4 Costs 45

4.2.5 Sensitivity Analysis 47

4.3 Industrial, Commercial, and Residential Space Heating 50

4.3.1 Background 50

4.3.2 Industry Growth 52

4.3.3 Effectiveness 52

4.3.4 Costs 56

4.4 Petroleum Refineries 56

4.4.1 Background 57

4.4.2 Industry Growth 57

4.4.3 Effectiveness 58

Chapter Page

4.4.4 Costs 61
4.4.5 Sensitivity Analysis 63
4.5 Sulfuric Acid Producers 65
4.5.1 Background 65
4.5.2 Industry Growth 66
4.5.3 Effectiveness 67
4.5.4 Costs 69
4.5.5 Sensitivity Analysis 69
4.6 Primary Nonferrous Smelters 72
4.6.1 Background 73
4.6.2 Industry Growth 73
4.6.3 Effectiveness 73
4.6.4 Costs 79
4.6.5 Sensitivity Analysis 81
5: IMPACT OF SULFUR TAX ON AIR QUALITY IN TWO HYPOTHETICAL AIR QUALITY CONTROL REGIONS 83
5.1 Introductions 83
5.2 Relationships between SO_2 Concentration and Sulfur Emissions 83
5.3 Hypothetical AQCR's 84
5.3.1 Hypothetical AQCR A 84
5.3.2 Hypothetical AQCR B 85
5.4 Effect of Sulfur Tax on Emissions and Ambient SO_2 Concentrations 85
5.4.1 Sulfur Emissions 85
5.4.2 Ambient SO_2 Concentrations 85
BIBLIOGRAPHY 88

Appendix Page

A: SULFUR EMISSIONS FACTORS AND CONTROL COSTS FOR FUEL COMBUSTION SOURCES 95

  A.1 Emission Factors 95

  A.2 Sulfur Emissions Control Alternatives and Cost 99

    A.2.1 Sulfur Oxide Removal from Stack Gases 99

      A.2.1.1 Dry Limestone Absorption 101

      A.2.1.2 Wet Lime Scrubbing 101

      A.2.1.3 Magnesia Base Scrubbing 103

    A.2.2 Fuel Switching 103

      A.2.2.1 Coal 105

      A.2.2.2 Oil 110

        A.2.2.2.1 Distillate 112

        A.2.2.2.2 Residuals 114

      A.2.2.3 Gas 117

      A.2.2.4 Transportation Costs 117

    A.2.3 Emissions Reductions and Costs 118

B: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR PETROLEUM REFINERIES 121

  B.1 Emission Factors 121

    B.1.1 Catalyst Regenerators 121

    B.1.2 Claus Plants 123

    B.1.3 Fuel Combustion 123

  B.2 Sulfur Emissions Control Alternatives and Costs 124

    B.2.1 Catalyst Regenerators 124

    B.2.2 Claus Plants 126

    B.2.3 Fuel Combustion 127

    B.2.4 Emissions Reductions and Costs 127

C: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR SULFURIC ACID PRODUCERS 131

- C.1 Emission Factors 131
- C.2 Sulfur Emissions Control Alternatives and Costs 131
  - C.2.1 Gaseous Emissions Control 132
  - C.2.2 Mist Control 133
  - C.2.3 Emissions Reductions and Costs 134

D: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR PRIMARY NONFERROUS SMELTERS 137

- D.1 Emission Factors 137
  - D.1.1 Copper Smelters 137
  - D.1.2 Zinc Smelters 138
  - D.1.3 Lead Smelters 138
- D.2 Sulfur Emissions Control Alternatives and Costs 138
  - D.2.1 Copper Smelters 139
  - D.2.2 Zinc Smelters 142
  - D.2.3 Lead Smelters 145
  - D.2.4 Emissions Reductions and Costs 145

E: THE PROJECTED MARKET FOR RECOVERED SULFUR 151

- E.1 Introduction 151
- E.2 Major Sources of Sulfur 151
- E.3 Consumption of Sulfur 151
- E.4 Prices of Sulfur 153

F: THE EFFECT OF THE CORPORATE TAX STRUCTURE ON THE PROJECTED EMISSION LEVELS 157

G: SOME ASPECTS OF SULFUR EMISSION TAXES IN THE PRESENCE OF ADVANCING CONTROL TECHNOLOGY FOR POWER PLANTS 161

G.1 Introduction 161

G.2 Some Expected SO_2 Control Alternatives for Power Plants, 1980-1985 162

G.2.1 SO_2 Control Alternatives for Existing Power Plants 162

G.2.1.1 Citrate SO_2 Removal Process 162

G.2.1.2 Double Alkali SO_2 Removal Process 162

G.2.1.3 Gasified Coal 163

G.2.2 SO_2 Control Options for New Power Plants 163

G.2.2.1 Fluidized Bed Combustion Process 163

G.2.2.2 Combined Cycle Power Systems 164

G.2.2.3 Nuclear Power Plants 164

G.2.3 Summary 165

G.3 Theoretical Aspects of Producer Responses to the Emissions Tax Over Time 165

G.3.1 A Simple Model of Cost Minimization Without Emissions Control Policies 165

G.3.2 Cost Minimization Over Time in the Presence of Emissions Control Policies 167

G.4 A Preliminary Empirical Investigation of Sulfur Emission-Tax-Induced Delays in the Removal of Sulfur Oxides from Stack Gases 171

H. STATE-BY-STATE PROJECTIONS OF THE EFFECTIVENESS AND COSTS OF A TAX ON SULFUR EMISSIONS 179

LIST OF FIGURES

Figure		Page
1	Emission source behavior in response to a tax	14
2	Socially optimal level of emissions	14
3	Total cost* of reductions in sulfur emissions from all major sources combined--1978	26
4	Marginal cost* of reductions in sulfur emissions from all major sources combined--1978	26
5	Effectiveness of a tax on the sulfur emissions from all major sources combined--1978	27
6	Total costs induced by a tax on the sulfur emissions from all major sources combined--1978	29
7	Tax revenues from a tax on sulfur emissions from all major sources combined--1978	30
8	The incidence of a sulfur emissions tax	32
9	Projected impact on consumer prices of a tax on the sulfur emissions from all major sources--1978	35
10	Steam-electric power plant trends	39
11	Effectiveness of a tax on sulfur emissions: steam-electric power plants--1978	43
12	Total costs induced by a tax on sulfur emissions: steam-electric power plants--1978	45
13	Average total incremental costs per kilowatthour induced by a tax on sulfur emissions: steam-electric power plants--1978	47
14	Effectiveness of a tax on sulfur emissions: area sources--1978	55
15	Total cost induced by a tax on sulfur emissions: area sources--1978	56
16	Petroleum refining trends	58

LIST OF FIGURES

Figure		Page
17	Effectiveness of a tax on sulfur emissions: petroleum refining--1978	61
18	Total costs induced by a tax on sulfur emissions: petroleum refining--1978	62
19	Average total incremental costs per barrel of refined oil induced by a tax on sulfur emissions: petroleum refining--1978	62
20	Sensitivity of the effectiveness and total costs of a tax on sulfur emissions to the value of recovered sulfur: petroleum refining--1978	63
21	Sulfuric acid production trends	66
22	Effectiveness of a tax on sulfur emissions: sulfuric acid producers--1978	69
23	Total costs induced by a tax on sulfur emissions: sulfuric acid producers--1978	70
24	Average total incremental costs per tone of acid production induced by a tax on sulfur emissions: sulfuric acid producers--1978	70
25	Sensitivity of the effectiveness and total costs of a tax on sulfur emissions to the value of recovered sulfur: sulfuric acid producers--1978	71
26	Primary nonferrous smelting trends	74
27	Effectiveness of a tax on sulfur emissions--1978	79
28	Total costs induced by a tax on sulfur emissions--1978	80
29	Average total incremental costs per ton of product induced by a tax on sulfur emissions--1978	80
30	Sensitivity of the effectiveness and total costs of a tax on sulfur emissions to the value of recovered sulfur--1978	81
31	Effectiveness of a tax on sulfur emissions for two hypothetical Air Quality Control Regions	85
32	Relationship between tax rates and air quality for two hypothetical Air Quality Control Regions	87

LIST OF FIGURES

Figure		Page
A.1	Coal-producing districts	108
A.2	Bituminous coal price trends	109
A.3	Sources of supply of petroleum	111
A.4	Distillate consumption	111
A.5	Residual fuel oil consumption	115
A.6	Oil-producing regions	115
A.7	Total cost of reductions in sulfur emissions: steam-electric utilities	119
A.8	Marginal cost of reductions in sulfur emissions: steam-electric utilities	119
A.9	Total cost of reductions in sulfur emissions: area sources	120
A.10	Marginal cost of reductions in sulfur emissions: area sources	120
B.1	Total cost of reductions in sulfur emissions: petroleum refineries--1978	129
B.2	Marginal cost of reductions in sulfur emissions: petroleum refineries-1978	129
C.1	Total cost of reductions in sulfur emissions: sulfuric acid producers	135
C.2	Marginal cost of reductions in sulfur emissions: sulfuric acid producers-1978	136
D.1	Total cost of reductions in sulfur emissions: primary nonferrous smelters-1978	148
D.2	Marginal cost of reductions in sulfur emissions: primary nonferrous smelters	149
E.1	Sulfur consumption trends	152

LIST OF FIGURES

Figure		Page
E.2	Sulfur price index	154
G.1	Loci of anticipated costs of new SO_x control processes (available in T* years beyond 1978) below which a cost minimizing 1500 MW model power plant would defer SO_x stack gas cleaning	175
G.2	Loci of anticipated costs of new SO_x control processes (available in T* years beyond 1978) below which a cost minimizing 800 MW model power plant would defer SO_x stack gas cleaning	176
G.3	Loci of anticipated costs of new SO_x control processes (available in T* years beyond 1978) below which a cost minimizing 350 MW model power plant would defer SO_x stack gas cleaning.	177
H.1	Marginal cost of reductions in sulfur emissions from all major sources combined in selected States	180
H.2	Effectiveness of a tax on the sulfur emissions from all major sources combined in selected States	180

LIST OF TABLES

Table		Page
1	Major Sources of Sulfur Emissions	4
2	Summary of the Projected Effectiveness and Costs of a National Tax on the Major Sources of Sulfur Emissions--1978	8
3	Comparison of Costs of Clean Air and Emissions Tax Results--1978	9
4	Projected Sulfur Emissions from Major Sources--1978	27
5	Projected Response of all Major Sources Combined to a National Tax on Sulfur Emissions--1978	28
6	Projected Initial Price Increases Resulting from a Tax on Sulfur Emissions	34
7	Projected Sulfur Emissions from Steam-Electric Utilities--1978	41
8	Projected Response of all Steam-Electric Power Plants National Tax on Sulfur Emissions--1978	42
9	Effects of the Sulfur Emissions Tax on the Distribution of Flue Gas Desulfurization Choices for Steam-Electric Power Producing Units	44
10	Distribution of Steam-Electric Utilities' Demand for Coal and Residual Oil by Sulfur Content--1978	44
11	Percentage Distribution of Control Costs	46
12	Sensitivity of Effectiveness and Total Cost of Tax on Sulfur Emissions to Residual Fuel Oil Prices: Steam-Electric Power Plants--1978	48
13	Distribution of Steam-Electric Utilities' Demand for Coal and Residual Oil by Sulfur Content with Increased Prices for Residual Oil--1978	49
14	Effects of Residual Oil Price Increases on the Percentage Distributions of Flue Gas Desulfurization Choices for Steam-Electric Power Producing Units	51
15	Area Source Fuel Consumption--1970	52
16	Projected Sulfur Emissions from Area Sources--1978	53

LIST OF TABLES

Table		Page
17	Projected Response of all Area Sources to a National Tax on Sulfur Emissions--1978	54
18	Distribution of the Combined Demand of Steam-Electric Utilities and Area Sources for Coal and Residual Oil--1978	55
19	Projected Sulfur Emissions from Petroleum Refineries--1978	59
20	Projected Response of all Petroleum Refineries to a National Tax on Sulfur Emissions--1978	60
21	Sensitivity of the effectiveness and Total Cost of a Tax on Sulfur Emissions to the Control Cost Estimates: Petroleum Refineries--1978	64
22	Projected Emissions from Sulfuric Acid Production--1978	67
23	Projected Response of all Sulfuric Acid Plants to a National Tax on Sulfur Emissions--1978	68
24	Sensitivity of Effectiveness and Total Costs of Tax on Sulfur Emissions to the Control Cost Estimates: Sulfuric Acid Producers--1978	72
25	Projected Sulfur Emissions from Primary Nonferrous Smelters--1978	75
26	Projected Response of all Primary Nonferrous Smelters to a National Tax on Sulfur Emissions--1978	76
27	Sensitivity of Effectiveness and Total Cost of Tax on Sulfur Emissions to Control Cost Estimates: Primary Nonferrous Smelters--1978	82
28	Sulfur Emissions by Source for two Hypothetical Air Quality Control Regions	84
29	Annual Sulfur Emissions and Percent Reduction with Various Tax Rates	86

LIST OF TABLES

Table		Page
A.1	Area Source Fuel Consumption by State, 1970	96
A.2	Steam-Electric Plant Sulfur Emissions Stack Gas Control Alternatives	99
A.3	Sulfur Emissions Control Cost Equations for Steam-Electric Utilities Using Flue Gas Desulfurization	100
A.4	Geographic Distribution of Known Recoverable Reserves of Coal	106
A.5	Production of Commercial Bituminous and Subbituminous Coal--1970	107
A.6	Projected Maximum Production of Commercial Bituminous Coal--1978	107
A.7	Coal Prices by District	112
A.8	Sources of Residual Fuel Oil	113
A.9	Crude and Residual Oil Imported into the United States from the Middle East	113
A.10	Projected Maximum U.S. Production of Residual Oils--1978	116
A.11	Oil and Gas Average Btu Contents	116
A.12	Oil and Gas Average Btu Contents	117
A.13	Coal Average Btu Contents by Origin	118
B.1	Estimated U.S. Petroleum Refinery Sulfur Balance--1970	122
B.2	Sulfur Emissions Factors for Petroleum Refineries	123
B.3	Sulfur Emission Control Alternatives for Petroleum Refineries	125
B.4	Sulfur Emission Control Costs for Petroleum Refineries	126
B.5	Size Distribution of Petroleum Refineries	128
C.1	Sulfur Emission Factors for Sulfuric Acid Plants	132
C.2	Sulfur Emission Control Alternatives for Sulfuric Acid Plants	133

LIST OF TABLES

Table Page

C.3 Sulfur Emission Control Costs for Sulfuric Acid 135

C.4 Size Distribution of Sulfuric Acid Plants 136

D.1 Sulfur Emission Factors for Copper Smelters 137

D.2 Sulfur Emission Factors for Zinc Smelters 138

D.3 Sulfur Emission Factors for Lead Smelters 139

D.4 Sulfur Dioxide Removal Efficiencies of Sulfuric Acid Plants as a Function of Input Concentrations for Single- and Double-Absorption Systems 141

D.5 Copper Smelter Plant Types 141

D.6 Sulfur Emission Control Alternatives for Copper Smelters 142

D.7 Sulfur Emission Control Costs for Copper Smelters 143

D.8 Sulfur Emission Control Alternatives for Zinc Smelters 144

D.9 Sulfur Emission Control Costs for Zinc Smelters 145

D.10 Sulfur Emission Control Alternatives for Lead Smelters 146

D.11 Sulfur Emission Control Costs for Lead Smelters 146

D.12 Size Distribution of Copper Smelters 147

D.13 Size Distribution of Zinc Smelters 148

D.14 Size Distribution of Lead Smelters 148

E.1 Projected Sulfur Emissions--1978 153

E.2 Sulfur Production Costs by Source 156

G.1 Projected Costs and Availability of Sulfur Emission Control Alternatives for Power Production, 1980-1985 166

G.2 Model Plant Parmeters and Projected SO_x Removal Costs 171

H.1 Projected State-by-State Responses to a National Tax on Sulfur Emissions 181

A PROJECTION OF THE EFFECTIVENESS AND COSTS OF A NATIONAL TAX ON SULFUR EMISSIONS

Chapter 1: INTRODUCTION AND SUMMARY

1.1 Background

Writing in 1920, the British economist A. C. Pigou observed that London received only 12 percent of the available sunlight due to the smoke in the atmosphere from factory chimneys and that the smoke inflicted "a heavy uncharged loss on the community, in injury to buildings and vegetables, expenses for washing clothes and cleaning rooms, expenses for the provision of extra artificial light, and in many other ways."* Pigou identified the reason for the smoke as the difference between the private costs and the social costs of production. Industrialists, in producing consumer goods and services at minimum private costs also imposed an additional social cost on third parties since the value of clean air was not included as part of the costs of production. The assimilative capacity of the atmosphere was free to emitters. Consequently, industrialists had no incentive to install "smoke-preventing appliances," for the costs of such "appliances" would simply raise the costs of production, thus making the affected products less price-competitive.

Pigou advocated intervention by government to remove the divergence between social and private costs, specifically citing emissions taxes as a possible mechanism for removing the divergence. Today, more than half a century later, economists are reiterating the same basic recommendation. In particular, a tax on sulfur emissions has been proposed both by members of government and private citizens on the basis of the effectiveness of such a tax in reducing sulfur emissions to desirable levels at the smallest total cost to society. This study provides an initial examination of the effectiveness and costs of a uniform national tax on the major emitters of sulfur (or more exactly, sulfur compounds).

Since current legislative and political considerations, coupled with the still advancing state-of-the-art in sulfur oxide flue gas control techniques, make the implementation of such a tax unlikely before 1978, this study is directed toward the goal of evaluating the potential costs and implicit reductions in emissions that would occur in the presence of various tax rates on sulfur emissions during that year. Though most of the results address the national impact of such a policy tool on each of five major sulfur emission source categories, some attention is also given to regional effects and to the intrafuel price effects of such a tax.

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*A. C. Pigou, The Economics of Welfare. London: Macmillan and Co., Ltd., 1920, pp. 160-61.

1.2 Effects of Sulfur Oxides

Sulfur is present in polluted atmospheres as a component of both particulate matter and gases. In particulate matter it may occur as a sulfate salt or as highly corrosive sulfuric acid. As a gaseous component, sulfur is present in hydrogen sulfide, mercaptans, and sulfur oxides.

The principal physiological effect of sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) is bronchoconstriction, leading to an increase in airway resistance. Epidemiological studies of acute air pollution episodes have shown a significant association between excess mortality and morbidity and elevated SO_2 concentrations with associated particulate matter. People with preexisting diseases of the heart and lungs are particularly vulnerable to the effects of SO_2.

Nonhealth effects of sulfur compounds include reduction of visibility by suspended sulfate and sulfuric acid particles, accelerated corrosion of metals at relative humidities greater than 70 percent, and deterioration of limestone, marble, roofing slate, and mortar. Textile fibers are damaged, fabrics fade, leather loses its strength, and paper is embrittled in the presence of SO_2. Sulfur dioxide and H_2SO_4 at sufficient concentration for an appropriate length of time also cause injury to ornamental and economic crops.

Based on an examination of available data on the relationship between concentration and the occurrence of adverse effects, the Environmental Protection Agency (EPA) has set National Ambient Air Quality Standards for SO_2. By maintaining sulfur oxides concentrations at or below those specified in the standards, it is hoped that adverse effects will be avoided.

To achieve the National Ambient Air Quality Standards, several States have developed implementation plans that rely principally on regulation of sources, specifying such things as the sulfur content of fuels and allowable SO_2 emissions. This research evaluates the effectiveness of a national tax on sulfur emissions either as an alternative or as a supplemental strategy to achieve the National Ambient Air Quality Standards for sulfur oxides.*

1.3 The Concept of a Tax on Sulfur Emissions

Emissions taxes are government-imposed prices on the discharges of pollutants to the atmosphere. Their purpose may not be to raise revenue, although they would have that effect; rather their purpose should be to encourage the equalization of both the marginal costs and the marginal benefits of using the assimilative capacity of the atmosphere or to induce the attainment of desired air quality levels at minimum cost. The costs of emission reductions in the presence of a tax would be internalized to the firm and typically incorporated to some degree in product prices. This would force producers and consumers of that product to pay directly the costs of residuals treatment and disposal. This situation contrasts with that of present air pollution externalities, in which these costs are passed along in the form of social costs to all pollution receptor groups.

In general, polluting sources can be expected to control emissions to the point where the incremental cost of removing the last unit of effluent from the process off-gases equals the tax rate. Taxes would then be paid on any uncontrolled discharges of pollutants to the atmosphere. The existence of these tax payments, which are costs to the firm, provide a persistent incentive to seek new, more cost-effective ways to control waste discharges.

1.4 Approach

This study of a tax on sulfur emissions, applied on a national basis, uses a comparative statics approach to project emissions in the absence of air pollution regulations (except the New Source Performance Standards) and emissions and costs under several alternative tax rates for 1978.

The study is confined to five major sources of sulfur emissions which account for over 90 percent of all estimated sulfur emissions (table 1). These sources range from steam-electric plants which contribute

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*Note that it is quite reasonable for either Federal or regional pollution control authorities to consider the addition of a sulfur tax to present regulations. Such an approach would have two effects: first, it would provide an additional incentive for plants to meet already existing regulations; second, it would retain at least some of the cost-effectiveness properties of a tax while assuming a minimum level of control (under the regulation) applicable to all sources.

Table 1. Major sources of sulfur emissions

Emissions source	Percent of total
Fuel combustion	
Steam-electric	50.6
Area sources*	22.8
Industrial process	
Primary nonferrous smelters	11.7
Petroleum refineries	6.3
Sulfuric acid	1.8
Total	93.2

*Space heating and industrial boilers.

Source: Nationwide Inventory of Air Pollutant Emissions 1968. Raleigh, N. C.: NAPCA, August 1970.

over 50 percent of total sulfur emissions, to sulfuric acid plants which account for less than 2 percent of the total sulfur emissions.

An inventory of these sources in 1970 was developed which contains data on plant capacities and the process configurations necessary to estimate emissions and control costs. This inventory was based on previous inventories used by RTI and supplemented with current information obtained from EPA and from trade sources to make it applicable to 1970. In spite of these efforts, some errors and omissions in the inventory are possible. It is doubtful, however, that they would be significant enough to affect the projected effectiveness or costs of the tax on sulfur emissions on a national level. Because the tax was to be analyzed for 1978, projections of industry growth were employed. New plants were added to the inventory on the basis of available projections of industry growth and observed trends in plant size and process types.

Sulfur emission control alternatives were identified and their costs were estimated from data presented in previous studies for EPA, based on private communications with EPA industry specialists, or developed by RTI. The control or abatement costs were aggregated from estimates specific to source location, plant capacity, and process configuration. All control costs are on an annualized basis.

The number of control alternatives costed for each source depended on available data. In some cases, only two control alternatives appeared feasible. In the case of steam-electric utilities, about 1,000 combinations of fuels, fuel origin, sulfur content, and flue gas desulfurization alternatives were costed for each utility.

A computer model was developed to determine each plant's behavior under a tax, compute emissions and costs, sum the results over the industry, and print the results in tabular form. It is assumed that emissions sources will minimize the sum of the costs of emissions reductions and tax outlays by selecting the level of emissions reductions where the net marginal costs of these reductions (MC_{ER}), after allowing for the sale (if any) of byproducts, equals the tax rate (TX). That is, $MC_{ER} = TX$. At this level of emissions reductions, the total pollution-related costs to the source (i.e., annualized control costs plus tax payments) are minimized. All sulfur values presented in this report are in terms of sulfur, not sulfur dioxide (SO_2), which is 50 percent sulfur.

This study has followed the convention used in the Cost of Clean Air and many other EPA-sponsored studies in using non-tax-adjusted cost estimates. It is recognized, however, that (because tax payments on sulfur emissions would be tax deductible expenses) the effective tax rate is overstated by the marginal percentage rate of corporate income taxes faced by the firm. This argument, of course, assumes that the firm has enough profits for the tax payments to be a usable tax deduction. It is also the case, however, that all of the abatement costs are overestimated by at least the same factor since all variable costs associated with pollution control are also fully tax deductible and since the capital costs of pollution control devices are subject to special accelerated depreciation schemes. In effect, this study assumes that the tax rate and the pollution control

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*Cost of Clean Air, 1973, "Annual Report of the Administrator of the Environmental Protection Agency to the Congress of the United States." Subsequent references to Cost of Clean Air mean any issue of the annual report.

costs are overstated by approximately the same factor. As a result the projected emissions reductions would be unchanged by including corporate income tax considerations since both the marginal costs of emissions reductions (MC_{ER}) and the tax rate (TX) can be rescaled by a constant fraction to derive approximations of the net control costs and net tax rate. See appendix F for a discussion of the problems and biases implicit in these assumptions.

Other alterations in the relative price of pollution control hardware--due to the issuance of municipal or State revenue bonds to subsidize corporate financing of pollution control devices, to preferential exemptions from property taxes on pollution control gear, and to pollution control related State income tax preferences--are likely to enhance further the attractiveness of control hardware over tax payments. These, coupled with the effects of the Federal corporate tax structure, are, in RTI's judgment, likely to cause some understatement in the estimated emissions reductions that would be achieved at the various tax rates projected in this report. The magnitude of that understatement, though difficult to evaluate for 1978 in view of continually emerging tax preferences on pollution control gear at the local level, is not likely to have caused large errors in predicted emissions reductions.

1.5 Assumptions, Limitations, and Capabilities

Several assumptions and limitations are present in this study regarding the data inputs and methodology employed.

It has been assumed that the emissions control alternatives identified in this study will be available in time for installation and operation by 1978. If supply conditions delay their applications, the effectiveness of the tax for 1978 will be less than, and the costs greater than, those projected.

Because of the lack of data and the scope of this study, only a limited number of control alternatives have been evaluated for each source. Most of these alternatives have high control efficiencies (80 to 99 percent). It is likely, however, that other control alternatives, including process changes, would be induced with an emissions tax. This would tend to increase the projected effectiveness of the tax in motivating emissions reductions and, further, it would tend to lower costs from those presented in this study.

The dynamics of fossil-fuel supply and prices have not been explored to the extent possible. These factors will play a critical role in influencing the effectiveness and the costs, not only of the tax but also of the regulatory approaches to achieving emissions reductions. However, a preliminary analysis has been conducted of how the projected effectiveness and costs of the tax may be influenced by future fuels supply.

The most obvious comparison to this report is the annually published Cost of Clean Air. Any reader making comparisons should be alert to some critical differences between the underlying assumptions and methodologies of the two reports. The most obvious difference is that the Cost of Clean Air shows total costs for reductions in sulfur dioxide emissions while this report shows costs for sulfur, which constitutes one-half of the equivalent mass of sulfur dioxide. Secondly, this study accommodates not just one but several control options for every emissions source. For fuel combustion sources, these options include: fuel switching among several sulfur content fuel types, distinguished by location of origin; three separate flue gas control hardware options; and emissions tax payments. For other industrial sources, the control options include choices between various hardware or process changes for each process source and tax payments. The Cost of Clean Air, on the other hand, generally has taken an inflexible approach in imposing a control option on specific plants and totaling up the resultant estimates. Furthermore, where fuel switching has been considered only, the Cost of Clean Air has incorporated a simple, low sulfur fuel cost premium to derive the cost of the alternative fuel. The model of this study was more detailed in that fuel transportation costs and supply considerations were built into the simulated array of fuel options available to each plant. A final consideration is that RTI attempted to incorporate current refinements in the estimates of control hardware costs. In some cases, these estimates (reported in appendixes A through D) differed substantially from those used in the Cost of Clean Air. In summary, the control costs projected here are not fully comparable with those reported in the Cost of Clean Air owing, mainly, to different methods of deriving low sulfur fuel prices, to the wider array of control choices available to plants, and to the incorporation of more recent estimates of control hardware costs. Despite these differences, however, the interested reader will note that the cost estimates of the two reports, after appropriate adjustments for the units difference (sulfur versus sulfur dioxide), are within the same order of magnitude.

1.6 Summary of Findings

Based on the results of the research presented in this study, it appears that a national tax on the sulfur emissions of the five major sources of this pollutant would be an effective means of inducing emissions reductions. Specifically, table 2 shows the reductions, costs, and tax payments projected for selected tax rates.

Although no direct comparisons have been developed here between the costs under a system of emissions standards and those under a system of emissions taxes, the aggregate cost to the Nation of emissions reductions with a tax will be no higher than those under an emissions standards approach to air quality management for a given reduction in emissions.* In all likelihood, these costs under a tax would be substantially less

Table 2. Summary of the projected effectiveness and costs of a national tax on the major sources of sulfur emissions--1978

Tax rate (cents per pound of sulfur emissions)	Percentage reductions from unconstrained emission levels*	Total annual cost (billions)	Annualized control cost (billions)	Annual tax payment (billions)
5	53	$1.8	$0.9	$0.9
10	74	2.7	1.7	1.0
15	78	3.4	2.1	1.3
20	80	3.9	2.4	1.6
25	83	4.4	2.8	1.7
30	85	4.9	3.0	1.9

*The single exception is the assumption that the New Source Performance Standards are implemented regardless of the tax rate.

Source: Research Triangle Institute.

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*It is possible, in fact likely, that the sum of tax payments and control costs would be higher under an emissions tax policy than under standards. The total cost to society, however, must not include emissions tax payments since they simply represent income redistributions.

than those under an emissions standards approach because of the efficiency inducing properties of such a tax. A comparison of the emissions and cost data presented in the Cost of Clean Air with emissions and control cost data presented in this report under a tax strategy is presented in table 3. As discussed above, the reader should not conclude that the only basis for the differences in results between the Cost of Clean Air and this study is due to the relative efficiencies of taxes and regulations, since different methodologies were used to develop the cost of control estimates.

Under either a regulatory or tax approach, reductions in the emission of other pollutants may be achieved when controlling sulfur oxide emissions. This is due to the technology of the control alternatives. For example, in applying flue gas desulfurization technologies to sulfur oxide discharges, particulate emissions are usually reduced also. Similarly, switching from coal to oil may also reduce particulate as well as sulfur emissions. This added benefit has not been included in this study.

An emissions tax will significantly increase the demand for low sulfur fuels since they constitute a particularly attractive means of reducing sulfur emissions caused by fuel combustion. If the long-run supply of these

Table 3. Comparison of Costs of Clean Air and emissions tax results--1978

Source	Cost of Clean Air data[*]				Emissions tax data[†]			
	Uncontrolled emissions (thousand tons of sulfur)	Reductions in Emissions		Annualized control costs (million dollars)	Uncontrolled emissions (thousand tons of sulfur)	Reductions in emissions (thousand tons of sulfur)	Annualized control costs (million dollars)	Required tax rate to induce control (cents per pound of sulfur emissions
		(thousand tons of sulfur)	(percent)					
Steam-electric utilities	14,075	11,445	81.3	$1,860	11,396	9,265	$1,600	18
Area sources	3,887	3,070	79.0	1,342	5,678	4,486	500	20
Petroleum refineries	2,202	2,153	97.7	34	772	754	>27	>30
Sulfuric acid plants	929	642	69.1	29	385	266	33	10
Primary non-ferrous smelters	2,541	1,990	78.3	184	1,651	1,293	50	4

[*] Cost of Clean Air, Environmental Protection Agency, Washington, D.C., 1973.

[†] Developed from data presented in this study for same percent reductions in emissions as implied in the Cost of Clean Air.

fuels is inelastic, prices may increase fairly substantially. This study attempts to incorporate (into the determination of those fuel price projections) supply considerations that, at this juncture, seem reasonable. The reader is referred to section 3.2 and appendix A for more detailed discussions of these assumptions.

Though it is difficult to place confidence limits on the estimates of control costs used in this study, it is perhaps useful to distinguish the elements of control costs along with RTI's overall confidence in the estimated costs for those components. In general, the estimates of initial purchase costs of pollution control gear are quite good; estimation errors are on the order of ± 10 percent. Equipment installations costs, on the other hand, may vary by as much as 100 percent about the mean estimates. Among annualized costs, the errors in annualized cost are jointly determined by the above-mentioned capital cost estimates and potential errors in the discount rate. Operating, maintenance, and replacement costs consist of labor, power, water, and chemicals costs; all of these are subject to small variations (on the order of ± 10 percent) in the short run. A rough weighting of these estimates of error according to the share of each component in total annualized costs yields an average range of error in individual estimates of ± 16 to 20 percent.

For the industrial sources, use of alternative market values for recovered sulfur and sulfuric acid of ± 100 percent from the projected 1978 values ($10 per ton) is estimated to have little impact on the effectiveness and costs of the tax for most sources. Likewise, control cost deviations of ± 20 percent do not significantly alter the results of the study. It is likely, however, that the results are sensitive to the number of available control alternatives. If more alternatives were available to the industrial sources whose current control options manifest low removal efficiencies, the costs of the tax for these sources would be less than those projected, and the effectiveness greater at low-to-medium (5- to 15-cent) tax rates.

Chapter 2: THE APPLICATION OF EMISSIONS TAXES FOR POLLUTION CONTROL

2.1 Introduction

The problem of air pollution, viewed from an economic perspective, is one of overutilization of a scarce resource. The overutilized resource is the waste removal capacity of the air; that is, the capacity of the air to assimilate unwanted byproducts of production and consumption without imposing damages on such receptors as people and plant life. Historically, clean air has been a "free good", with more than enough available to saturate demand. However, the accelerated use of the atmosphere as a low-cost means of waste (or residuals) disposal has created health, property, and esthetic damages. Reduction in the damages inflicted upon society by a polluted atmosphere will require rationing of the use of the atmosphere for residuals disposal.

Residuals charges are a market-type mechanism for rationing environmental resources. Emissions taxes, one type of such charges, have been proposed by an increasing number of people concerned about the quality of the environment and the efficiency and costs of other, nonmarket types of strategies. This chapter briefly examines the rationale behind such charges with reference to a tax on sulfur emissions.

2.2 Air Quality and Market Failure

Most economic goods are rationed through a market process in which product prices reflect society's tastes and desires and in which costs reflect productive capabilities. This market process is generally regarded as a reasonably efficient means of resource rationing and allocation. Clean air, however, has no effective market. Even though one may desire clean air, there is no market where this preference can be registered. The result is the overutilization of the atmosphere for one service, residuals disposal, thereby transferring to society as a whole the costs of residuals disposal rather than incorporating these costs as a part of product costs and price. In this situation, an external diseconomy is said to exist. Since the costs of residuals disposal are not "internalized," product prices do not reflect alternative uses of the atmosphere. As a result, too many private goods whose production generates residuals and too few public goods such as clean air are produced. If the value to society of the atmosphere for purposes other than residuals discharges could be made to bear directly on discharging activities, polluters would reduce their discharges to the atmosphere.

Unfortunately, two conditions preclude the existence of an effective market for clean air. First is the absence of well-defined and enforceable property rights in the atmosphere. Second is the public-goods nature of clear air.

Of the two conditions, the public-goods nature of clean air is the primary reason for the lack of a market for clean air, since the creation of property rights in the atmosphere has limited practical applicability.* Public goods are goods that if supplied to one individual (e.g., national defense) are available to all. In the case of clean air, if air pollution is reduced in response to a "demand" on the part of some individuals, pollution will be reduced for all. Thus, appropriate aggregate information and responses needed to generate a market for public goods are generally lacking.

Nevertheless, because of the desirability of charging for the use of scarce resources, such as the assimilative capacity of the air, other pricing mechanisms are available in the absence of markets. The most often proposed alternative is the use of emissions taxes.

2.3 Emissions Taxes

Emissions taxes are a form of government intervention; the implicit rationale for them is that property rights in the atmosphere are vested in the public with the government acting as agent for the public interest by rationing the use of the atmosphere for waste disposal.

When prices (taxes) are placed on the use of the atmosphere for discharging the unwanted byproducts of production (e.g., sulfur oxides), emitters have an incentive to economize on their use of the environment just as relative resource prices currently guide decisionmakers to the most efficient use and combinations of land, labor, and capital. The abatement analysis burden is placed on corporate management which is, or will become, more knowledgeable regarding the cost-effectiveness of various control alternatives than government officials who are likely to have only incomplete information. Conceptually, at least, emissions taxes could be adjusted to the time of day, season, weather, or economic conditions in order to reflect the variable nature of damages.

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*A. M. Freeman, III, The Economics of Pollution Control and Environmental Quality, General Learning Press, 1971, pp. 1-27.

In the presence of an emissions tax, polluters will adjust their individual level of control so that the last ton of emission reduction from all sources imposes the same cost on each source. This is significant for it means that the reduction in total emissions is achieved at the least amount of the control cost.

Furthermore, the emissions tax provides a continuing incentive for firms to seek newer and more efficient means of controlling their discharge and to avoid judicial delay tactics. These desirable tendencies are not usually encouraged under a system of emissions standards.

With the imposition of an emissions tax, polluters can be expected to pursue the least-cost means of residuals management. These costs can be conveniently divided into two components: control costs and emissions tax payments. The sum of these two costs--after adjusting for the effect of income taxes--will be minimized. The extent to which emissions are controlled will depend on the relative cost of control and the tax rate. This decision analysis can also be examined on a per unit basis.

For example, as shown in figure 1, assume that before a tax is levied on emissions, the plant is emitting E tons per year. A tax (T) per ton of emissions will induce the plant to effect emissions reductions until the marginal cost of doing so equals the tax rate; it will produce A units of pollution control per year or, to put it another way, it will reduce its emissions from E to E-A. The control cost of emissions reductions will be the area OAB. The tax bill will be T(E-A); i.e., the tax rate times the flow of remaining emissions, whose product is equal to the area ABCE.

Ideally, the tax rate should be set at a level sufficient to induce reductions in emissions to a rate where the incremental damages of pollution equals the incremental cost of emissions reductions (see fig. 2). However, the application of emissions taxes to problems of air quality is not dependent on the availability of reliable information regarding damages from air pollution. Because air quality goals have been established by

EPA, emissions reductions necessary to achieve these air quality standards can be induced by emissions taxes. The remainder of the study explores the relationships among alternative emission tax rates, control costs, and resulting emissions.

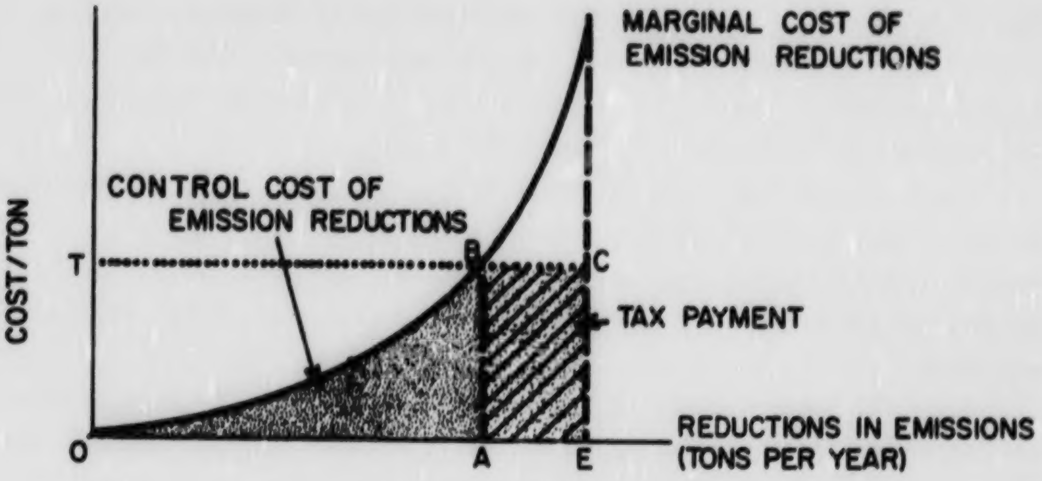
MARGINAL COST OF EMISSION REDUCTIONS
CONTROL COST OF EMISSION REDUCTIONS
COST/TON
T
B
C
TAX PAYMENT
O
A
E
REDUCTIONS IN EMISSIONS (TONS PER YEAR)

Figure 1. Emission source behavior in response to a tax.

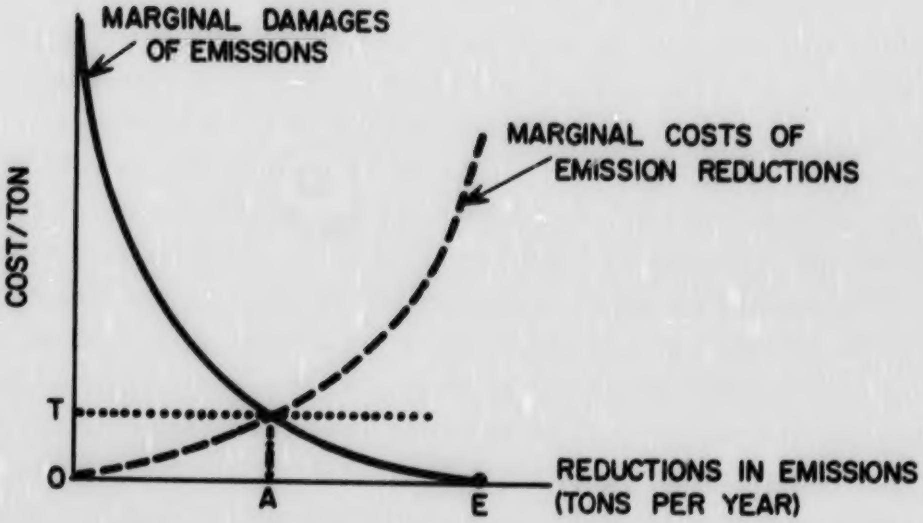
MARGINAL DAMAGES OF EMISSIONS
MARGINAL COSTS OF EMISSION REDUCTIONS
COST/TON
T
O
A
E
REDUCTIONS IN EMISSIONS (TONS PER YEAR)

Figure 2. Socially optimal level of emissions.

Chapter 3: ANALYSIS OF THE EFFECTIVENESS AND COSTS OF A TAX ON SULFUR EMISSIONS

3.1 Introduction

To estimate the probable effectiveness and costs that would result from implementation of a tax on sulfur released into the atmosphere, an emissions response model was developed and applied to three industrial process sources, steam-electric utilities, and area heating sources. When combined, these sources account for over 90 percent of U.S. sulfur emissions. The model calculates controlled emissions and costs at specified tax rates for each plant and aggregates each industry for the Nation as a whole. Controlled emissions and costs for area sources are also estimated and added to provide national totals. This analysis was performed for the year 1978, 5 years hence, on the assumption that the projected control systems will be availble and could be installed by then. The factors used and the results of the analysis are given below.

3.2 The Emissions Response Model

The procedure of this study is to approximate, heuristically, the individual plant's reponse to an emissions tax. This is accomplished by the use of an emissions response model developed for this study. Throughout the analysis several simplifying assumptions are made regarding plant or source operation regardless of classification. Those assumptions are:

(1) That product output at all existing point sources remains constant; no plants go out of business or curtail production in response to emissions control taxes;

(2) That the plant manager chooses the combination of emissions tax payments and emissions control options in such a way that his total outlay is minimized;

(3) That expected annualized control costs are sufficiently approximated by previous studies for EPA cited herein (and discussed in detail in appendixes A through D);

(4) That the finite number of control options studied here are representative of those that producers will face in 1978; i.e., that no extraordinary technical changes in sulfur oxide control technology will occur during the next 5 years.

The remainder of this section discusses the assumptions and methodology for each of the broad emission source categories: fuel combustion sources and industrial process sources.

3.2.1 Fuel Combustion Sources

The two broad types of fuel combustion sources are steam-electric power plants and area sources; i.e., commercial, residential, and industrial space heating. Both of these sources are assumed to have the option of fuel switching; i.e., changing from one fuel type to another or from one sulfur content to another. Only power plants are assumed to have the option of removing entrained sulfur from the carrier gas. The following paragraphs first discuss the assumptions regarding fuel availability supplies and prices (sec. 3.2.1.1). With that background, the next sections summarize the additional assumptions and methodology involved in deriving the cost-minimizing control options for steam-electric power plants (sec. 3.2.1.2) and area sources (sec. 3.2.1.3). More detailed discussions are presented in appendix A.

3.2.1.1 Fuel Supplies and Prices

3.2.1.1.1 Fuel Supplies. Because available fuel supplies are not uniformly distributed with respect to sulfur content, Btu value, and location, it has been necessary to explicitly incorporate consideration of these parameters in this study. The approach employed for each fuel is presented below.

a. Coal. The 1978 maximum production of coal was projected within each of seven designated coal-producing basins by sulfur contents. The method of projection relied on a technique developed by the MITRE Corporation. The projections involve the use of a growth rate within each of the 7 basins for each of 9 sulfur content groupings. Those projections yield 63 (9 sulfur contents times 7 basins) estimates of maximum commercial bituminous coal production.

The seven basins were further subdivided according to the 19 coal-producing districts defined by the U.S. Department of Interior using projected regional proportions developed by Battelle. The resulting projections comprised 171 maximum supply estimates for coal (19 districts times 9 sulfur contents). The Btu content of these coals were assumed invariant within each of the 19 districts; the Btu values were averages for each region reported by the MITRE Corporation. Initially prices of the 171 fuels at their origins were adapted from the Battelle study. Subsequently they were adjusted in a manner discussed below (sec. 3.2.1.1.2). Because some sulfur content coals are not available within all regions, there were 21 empty cells in the fuel price and supply matrices. Consequently, the total number of coals, distinguished by district of origin and by sulfur content, is 150. To estimate the delivered price of these coals, RTI employed the transportation cost matrix developed by Battelle. That matrix provides estimates of shipping costs from the 19 coal regions to 50 destinations.

By adding those transportation costs to the coal prices at their origin for each of the 50 destinations, tables of delivered coal prices were developed. Each existing plant or source was then associated with one of those 50 destinations; this determined which of the 50 delivered-price vectors was relevant to a particular decision unit. Those vectors of delivered coal prices then become part of the decision unit's control costs.

b. Residual Oil. Only about one-third of annual U.S. consumption of residual oil is domestically produced. The maximum expected supplies of these domestic residual oils were projected for 1978 by Petroleum Administration for Defense (PAD) districts in a previous study by the MITRE Corporation. Those projected supplies were then allocated among the 12 oil-producing districts defined by the U.S. Department of the Interior, again on the basis of the distributions developed by Battelle. The result was a matrix of 48 domestically supplied oils (12 origins times 5 sulfur contents minus 12 empty cells). In addition, imported residual oil was also assumed available at four ports of entry (east coast, gulf coast, west coast, Great Lakes). Wellhead or POE prices were adapted from the Battelle study. A matrix of transportation prices developed by Battelle was used to develop estimates of delivered prices. These vectors of delivered oil prices, plus the coal prices determined as described above, are the fuel cost-sulfur content alternatives.

c. Natural Gas. For utilities, the supply of gas was assumed to be perfectly elastic to current users up to the quantities currently used and to be perfectly inelastic above those quantities. Therefore, no utilities were allowed to switch to gas or to increase gas consumption. For area sources, the market share of gas was assumed to remain constant at 1970 proportions among individual States. All gas prices assumed were those developed by Battelle.

d. Distillate Oil. Distillate oil, used primarily as a source of energy for area sources, was assumed to be unlimited in supply at prices projected by Battelle.

3.2.1.1.2 Fuel Price Adjustment. The first iteration of the model at a zero tax implied that the maximum projected supplies of coal and residual oil would be exceeded for some of the 198 domestically produced fuels. The most obvious way to handle this problem was to incorporate the 198 supply constraints while simultaneously minimizing the control costs associated with all fuel combustion sources. That approach, however, would have implied a major linear programming effort beyond the resource constraints of this project. The alternative chosen here was heuristic. Whenever the demand for a specific coal exceeded the maximum predicted supply, its price was arbitrarily increased by a small amount (generally on the order of 5 percent of base point prices). The entire model was then iterated again. This process was continued until the total domestic demand for coal was smaller than the corresponding total projected domestic supplies. The implicit assumption here of domestic self-sufficiency of coal appears warranted in view of the large U.S. reserves of coal, and historical consumption patterns.

For residual oil, demand exceeded domestic supply. However, additional supplies were assumed to be available from foreign suppliers at given prices. The sensitivity of the projected responses of the utilities to the assumed oil prices was, however, evaluated (see chapter 4). The general effect of this method of approximating price responses is likely to induce a downward bias in the costs of switching to low-sulfur fuels. Consequently, one could expect more control hardware applications than the model predicts.

3.2.1.2 Steam-Electric Power Plants. Each existing power plant was identified and its output, size, and operating characteristics recorded. Those plants were assumed to face three hardware options for the removal of sulfur from the combustion gases, each with an assumed potential control efficiency. They are the dry limestone, wet limestone, and magnesia scrubbing processes. The annualized costs of those options were intended to approximate the annual outlays whose present value over the firm's planning horizon equals the expected investment cost plus the discounted present value of their associated operating costs. Estimates of those costs were developed as functions of the sulfur content of the fuel, the megawatt capacities of the boilers at the plant, and the annual output at the plant. The cost estimating equations, formulated in previous studies for EPA, were adapted for this study. New power plants were projected to come on line in accordance with the National Coal Association listing of conventional steam-electric plants that are planned or under construction during 1971-1977.* These plants were assumed to adhere to the New Source Performance Standards. Consequently, new coal- or oil-fired plants were expected to install either a wet limestone or magnesia scrubbing system. The costs of those systems were not included in the total costs of control in this study.

Each plant then was assumed to minimize the total annual outlays of three components of costs: emissions tax payments, annualized abatement costs, and delivered fuel costs. For each tax rate considered, the computer simulation model scanned the sum of these three costs for every fuel type by sulfur content and for every control hardware option. About 1,000 alternatives exist for each source. The combination of hardware, fuel type, and emissions tax payments that minimized total outlay was the predicted response of the plant. The costs of these responses and the corresponding reductions in sulfur emissions at various tax rates per unit of sulfur emissions were aggregated over all plants.

3.2.1.3 Area Sources. Area sources comprise residential, commercial, and industrial fuel consumers. Since the available statistics relating numbers, size, and distribution of these heating units are either scant or nonexistent, this study attempted to simulate the response of individual emitters by analyzing each State as an aggregate. Though this approach has rather obvious drawbacks, the predicted behavioral response to the emissions taxes is felt to be a reasonable first approximation.

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*National Coal Association, Steam-Electric Plant Factors, 1969. Washington: National Coal Association, 1969, table 4.

The details of RTI's approach for an individual State are as follows. First, the percentages of total Btu input from coal, residual oil, natural gas, and distillate oil for each of the three area sources were determined for each State from published sources. Also, the absolute values of those fuel consumption rates for 1970 were recorded by State. Then the projected demands for 1978 were developed by applying separate growth rates to 1970 demands. No hardware control options were allowed for area sources. Further, among area sources only commercial and industrial users were allowed fuel switching.

a. Residential Sources. Since residential sources consume only natural gas and distillate oil, it was assumed that they did not switch to alternative fuels. It was further assumed that the residential fuel market shares accounted for by those two fuels remained constant over time. The growth rates applied to the 1970 State consumption rates were the projected State population growth rates published in the *Survey of Current Business*. Residential sources were then presumed to pay an emissions tax based on the sulfur content of those respective fuels. It is recognized that this is a rough first approximation that assumes demand is affected only by population growth and not by changes in the relative prices of distillate (because of the sulfur tax). If the demand for nonelectric home heating is relatively inelastic and if the supplies of natural gas are also quite limited, these assumptions are not likely to have caused serious prediction errors.

b. Commercial and Industrial Sources. Commercial and industrial emission source control options were assumed to be identical. The 1970 shares of total heat input accounted for by natural gas and by distillate oil among these sources were projected to remain stable through 1978. Absolute consumption values for each State were developed by applying the projected growth rate in overall national employment.

The proportion of heat input accounted for by residual oil and coal among commercial and industrial sources within a State was also assumed fixed at the 1970 proportion; but the relative shares of those two fuels within their jointly held market share was not.

The annualized cost whose present value was assumed to approximate the outlay necessary to install the coal-to-residual-oil-boiler conversion units was $11 per billion Btu.

The total outlays that commercial and industrial boilers are assumed to minimize, then, are the sum of the emissions tax and fuel costs of natural gas and distillate oil consumption--over which they have no control since the market shares accounted for by those two fuels remain constant--and the emissions tax, the fuel costs, and the boiler conversion costs of residual oil and coal consumption.

Once again it is clear that many complicated interrelationships have been rather quickly simplified: relative price sensitivities among fuels were not built in for natural gas and distillate oils vis-a-vis the aggregate of residual oil and coal consumption; growth trends were not developed on a State-by-State basis; no allowance was made for flue gas cleaning which may be feasible for large industrial sources; and all commercial-industrial sources in a State were forced to consume their present residual oil and coal heat inputs as either one or the other; i.e., no variable shares were allowed between these two fuels. Given sufficient data, these many analytical refinements might have been justifiable, but it was felt that the paucity of accurate information about these sources and their operating characteristics simply did not warrant attempts to build them in for this study. Yet, it was felt that the analysis did reflect a reasonable first approximation of the national emissions reductions that a sulfur tax would evoke from those area sources.

3.2.2 Industrial Process Sources

Industrial process sources of sulfur emissions comprise three industrial groupings: petroleum refineries (appendix B), sulfuric acid plants (appendix C), and primary nonferrous smelters (appendix D). The general approach for all of these sources was to determine hardware alternatives for sulfur oxide control and to annualize the cost of those installations. The individual plant's response to a tax was assumed to follow the cost-minimizing hypothesis. Whenever the total annual tax payments on the portion of emissions that were preventable with one of the hardware control options exceeded the annualized cost of that option, the plant was assumed to implement the control practice. Some of the details of this approach are discussed below for each major process source category.

3.2.2.1 Petroleum Refineries. The three major sources of refinery emissions are catalyst regenerators, Claus sulfur recovery plants, and fuel combustion sources. Approximately 13 percent of the sulfur content of crude oil processed at the plant is emitted from these three sources. The remainder is either recovered, emitted to waterways, or retained in marketed petroleum products.

The control option that was presumed most feasible for the control of emissions from catalyst regenerators was hydrodesulfurization of the catalytic cracker feedstock. This process essentially allows conversion of some of the sulfur in the feedstock to elemental sulfur. Each existing refinery in the United States was identified according to the type of catalyst regenerator in operation at the plant; then annualized costs of the hydrodesulfurization process were estimated according to several refinery capacities.

A refinery may or may not have a Claus plant, essentially a process that is used to convert hydrogen sulfide (H_2S) bearing refinery off-gases to elemental sulfur. If a refinery has no Claus plant, the H_2S stream is flared to the atmosphere resulting in substantial SO_2 emissions.

Each existing plant was then identified in terms of the type of catalyst regeneration it had in place and according to whether it had a Claus plant. The availability of EPA-estimated sulfur emission factors then facilitated an estimate of current emissions at each refinery.

The computer model simulated each refinery's response to an emissions tax in the following way. First, if the specific refinery's capacity did not correspond exactly to those for which control costs were estimated, interpolation was used. Then, sulfur emissions estimates were developed for these refinery sources from the emission factors and from estimates of refinery throughput. At each tax rate, total annual emissions tax payments associated with each of the three emissions sources were compared to the annualized cost of achieving some percentage reduction in those tax payments. If those costs were smaller than the associated tax savings, the refinery was projected to implement the subject control option.

This procedure resulted in aggregated estimates of abatement costs, of tax payments, and of emissions reductions across all three major emissions sources at any given refinery for each projected tax rate. Further aggregation across refineries yielded the industry emissions response curve for different levels of total abatement costs and for different sulfur tax rates or, identically, for different marginal costs of emissions reduction.

3.2.2.2 Sulfuric Acid Plants. Sulfuric acid plants emit sulfur in two forms: (1) as a gas, sulfur dioxide (SO_2), and (2) as an acid mist. The former results from incomplete absorption of SO_2 during the production process; the latter emerges from the absorption tower in the process off-gases. The two control techniques that were considered for gaseous emissions were the dual absorption and the sodium sulfite scrubbing processes. Their expected annualized costs are reported in appendix C.

For both gaseous and mist effluents, total potential emissions were computed using EPA estimates of emission factors and estimates of each plant's production of acid. By comparing total implied emissions tax payments under various tax rates to the annualized costs of control for each type of effluent, RTI projected whether or not abatement practices would be implemented. The choice criterion was whether or not the tax savings exceeded the annualized costs of the control option.

Total costs of tax payments, plus abatement costs, less the value of recovered sulfur were then aggregated for each plant and also across plants for the industry. The resulting projections of emissions reductions versus total annualized costs and versus marginal costs (tax rates) are reported in appendix C.

3.2.2.3 Primary Nonferrous Smelters. Primary nonferrous smelters include copper, lead, and zinc smelters. Each has a unique process operation that generates emissions at several points. Copper smelters emit SO_2 from the roaster (if the plant has one), reverberatory furnaces, and converters. Zinc smelters emit sulfur from the roaster or the roaster-sinterer, depending upon the type of smelting operation. Emissions from lead smelters derive mostly from the sintering operation, while small amounts are generated by blast furnace operation.

The major control techniques for smelters are: sulfuric acid plants, lime and limestone scrubbing, amine absorption, ammonia scrubbing, and sodium sulfite-bisulfite absorption. The relevant control options and their associated efficiencies for each smelter type were determined and are reported in appendix D. Similarly, annualized emission control costs were developed for each relevant option for representative plant sizes; these are also reported in appendix D.

After identification of each smelter, the annualized control costs for the specified control options were developed by interpolation from the previously mentioned cost estimates. By using the same technique previously applied to other process sources, a control option was projected to be implemented if its total annualized costs, less the value of recovered sulfur, were less than the tax payments implied in the absence of the device. Also, the results were aggregated for each smelter, across smelters for each nonferrous metals industry, and finally across all primary nonferrous sources. The aggregate of projected emissions reductions versus total annualized control costs and versus marginal costs (tax rates) is shown in appendix D.

3.3. Cost of Control Functions

A tax on sulfur emissions is expected to induce firms to control emissions to the level where the sum of the annualized emissions control costs and tax payments is minimized. Cost minimization is achieved by selecting the level of emissions reductions at which the incremental or marginal cost of control equals the tax rate. Projections of the effectiveness and costs of a tax on sulfur emissions depend, therefore, on the control alternatives assumed to be available, and their costs and effectiveness in reducing emissions. Extensive reviews of published studies and private communications with EPA and other knowledgeable sources have been conducted in order to identify the sulfur control alternatives likely to be available by 1978, and their costs and sulfur removal efficiencies. The alternatives selected and costed are presented in appendixes A through E. These alternatives have been costed for controlling sources of various sizes and process configurations to estimate cost functions for each source. A national listing of the major source of sulfur emissions (953 steam-electric power plants, 50 area sources (States), 263 petroleum refineries, 183 sulfuric acid plants, and 28 primary nonferrous smelters) and the process configuration of each has been used in order to conduct a plant-by-plant analysis.

The long run* total and marginal costs of functions, combined for all major sources under consideration, are shown in figures 3 and 4, respectively. These functions are plotted from analytical results of the emissions tax response model. The total cost function (LTC) increases at an increasing rate reflecting the higher costs of controlling smaller plants, the higher cost per ton of sulfur removal at high control efficiencies, and the price premiums for low sulfur fuels. The marginal cost function (LMC), being the first derivative of the total cost function, also increases at an increasing rate throughout the range of emissions reductions presented.

3.4 Effectiveness

The effectiveness of the tax is defined, for the purposes of this study, as the reduction in sulfur emissions that would be induced by a tax on sulfur emissions. The response of the emissions sources to the tax is a function of the cost of control and the tax rate. This analysis has been conducted in 5-cent increments for tax rates from 0 to 30 cents per pound of sulfur emitted.

In the absence of an emissions tax and without the application of any emissions standards except those applicable to new sources, sulfur emissions in 1978 are projected to be about 20 million tons anually from these major sources (see table 4). Eighty-five percent of these emissions would derive from fuel combustion sources. Since the projected rates of uncontrolled emissions from these sources require data on fuel demand, supplies, and prices by sulfur content (see appendix A) (all of which are difficult to project accurately), these projections of the uncontrolled emissions of fuel combustion sources should be cautiously interpreted.

The combined responses to the tax of all the major sources are provided in figure 5 and table 5. For small taxes of 1 to 10 cents per pound of sulfur, large reductions in sulfur emissions are projected. These projections hinge on RTI's cost estimates which indicate, for example, that at a marginal cost of sulfur removal of 10 cents per pound for all plants, the aggregate of all sulfur emissions sources would reduce emissions by

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*The "long run" is a time period long enough for firms to order and install control equipment or negotiate fuel contracts. It has been assumed that such adjustments can be made by 1978.

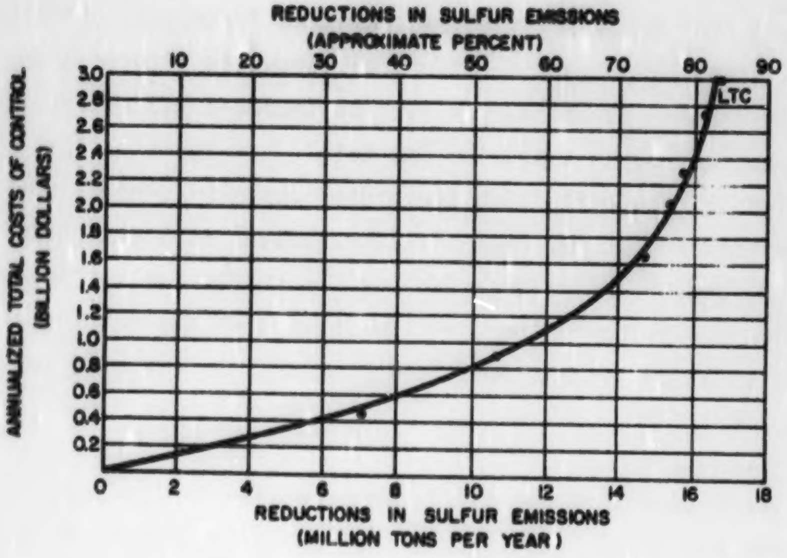

Figure 3. Total cost* of reductions in sulfur emissions from all major sources combined--1978 (*cost does not include emissions tax payments) (Source: Research Triangle Institute).

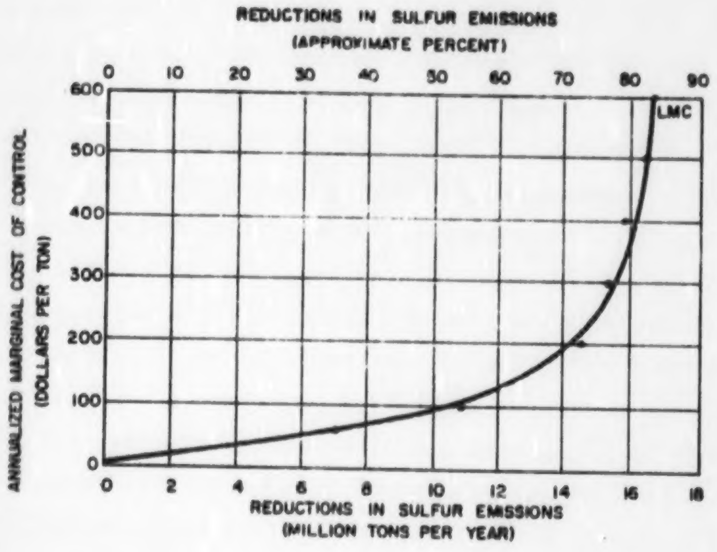

Figure 4. Marginal cost* of reductions in sulfur emissions from all major sources combined--1978 (*cost does not include emissions tax payments) (Source: Research Triangle Institute).

Table 4. Projected sulfur emissions from major sources--1978*

Source	Annual sulfur emissions (thousand tons of sulfur)	Distribution (percent)
Steam-electric power plants	11,396	57.3
Area sources	5,679	28.6
Petroleum refineries	772	3.9
Sulfuric acid plants	376	1.9
Primary nonferrous smelters	1,650	8.3
Total from all sources	19,873	100.0

*Assuming only controls required by the New Source Performance Standards.

Source: Research Triangle Institute.

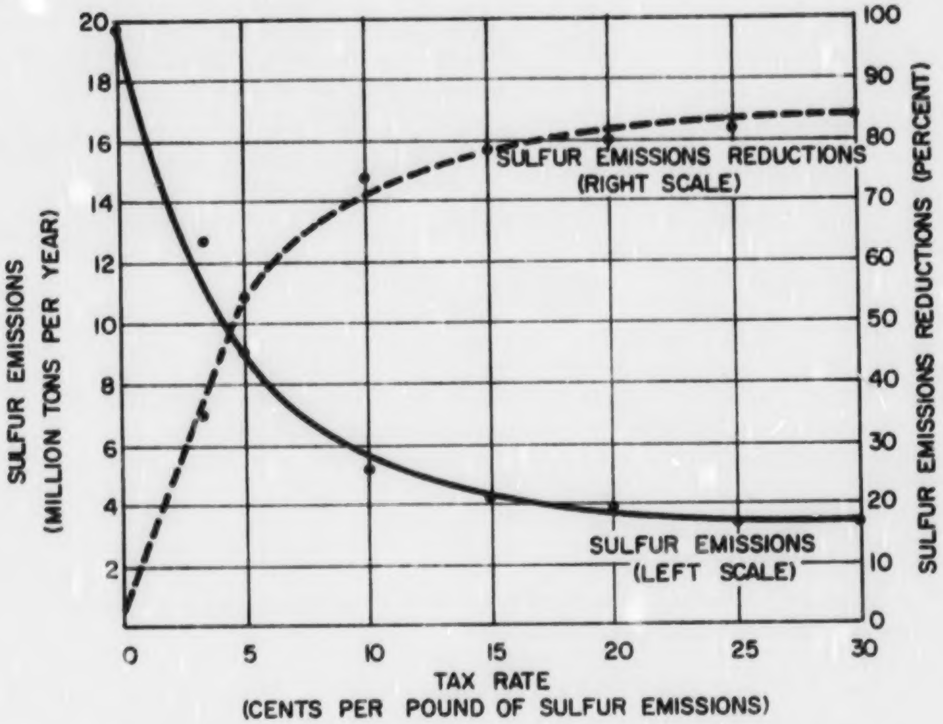

Figure 5. Effectiveness of a tax on the sulfur emissions from all major sources combined--1978 (Source: Research Triangle Institute).

Table 5. Projected response of all major sources combined to a national tax on sulfur emissions--1978

Emissions source	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual costs (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
Tax rate: 5 cents per pound of sulfur emitted					
Steam-electric utilities	5,159.0	6,237.0	$1,171,808	$ 655,881	$ 515,328
Area sources	2,854.7	2,822.8	466,497	181,026	285,472
Petroleum refineries	608.1	163.7	66,403	5,596	60,808
Sulfuric acid plants	385.4	0.0	38,546	0	38,546
Primary nonferrous smelters	278.9	1,371.5	85,098	57,206	27,892
Total from all sources	9,286.1	10,595.0	$1,828,352	$ 899,709	$ 928,646
Tax rate: 10 cents per pound of sulfur emitted					
Steam-electric utilities	2,961.8	8,434.2	$1,774,661	$1,182,231	$ 592,432
Area sources	1,494.3	4,183.2	654,265	355,391	298,874
Petroleum refineries	537.5	234.0	122,276	14,730	107,546
Sulfuric acid plants	96.7	288.8	59,410	40,074	19,335
Primary nonferrous smelters	110.6	1,539.9	98,345	76,233	22,112
Total from all sources	5,200.9	14,680.1	$2,708,957	$1,668,659	$1,040,299
Tax rate: 15 cents per pound of sulfur emitted					
Steam-electric utilities	2,277.7	9,118.2	$2,215,069	$1,531,656	$ 683,417
Area sources	1,383.1	4,296.5	796,647	382,344	414,306
Petroleum refineries	509.6	261.9	174,631	21,670	152,961
Sulfuric acid plants	60.9	324.4	66,797	48,486	18,311
Primary nonferrous smelters	94.8	1,555.6	108,837	80,386	28,451
Total from all sources	4,324.1	15,556.6	$3,361,981	$2,064,542	$1,297,446
Tax rate: 20 cents per pound of sulfur emitted					
Steam-electric utilities	1,948.2	9,447.7	$2,589,688	$1,810,295	$ 779,394
Area sources	1,377.2	4,300.3	934,526	383,646	550,881
Petroleum refineries	499.6	271.9	225,008	25,056	199,952
Sulfuric acid plants	48.7	336.7	72,018	52,525	19,492
Primary nonferrous smelters	81.4	1,569.1	117,873	85,323	32,550
Total from all sources	3,955.1	15,925.7	$3,939,113	$2,356,845	$1,582,269
Tax rate: 25 cents per pound of sulfur emitted					
Steam-electric utilities	1,599.5	9,796.5	$2,911,882	$2,112,048	$ 799,836
Area sources	1,115.2	4,562.2	1,059,893	502,214	557,680
Petroleum refineries	497.2	274.4	274,856	26,161	248,696
Sulfuric acid plants	47.4	337.9	76,831	53,110	23,722
Primary nonferrous smelters	79.6	1,570.9	125,894	86,103	39,791
Total from all sources	3,338.9	16,541.9	$4,449,358	$2,779,636	$1,669,725
Tax rate: 30 cents per pound of sulfur emitted					
Steam-electric utilities	1,432.1	9,963.9	$3,186,375	$2,326,992	$ 859,384
Area sources	1,030.9	4,646.6	1,164,706	546,153	618,554
Petroleum refineries	496.4	275.3	324,519	26,681	297,837
Sulfuric acid plants	46.9	338.5	81,548	53,392	28,158
Primary nonferrous smelters	79.2	1,571.2	133,820	86,288	47,532
Total from all sources	3,085.5	16,795.5	$4,890,980	$3,039,506	$1,851,477

Source: Research Triangle Institute.

more than 70 percent. Beyond tax rates of 10 cents, only small additional amounts of reduction are induced. For example, a 30-cent tax would only yield an additional 10-percent reduction.

3.5 Costs

The costs of sulfur emissions tax strategy would consist of the tax payments plus the costs of control, both of which would initially be paid by the polluting sources. To the industry, there is no significant conceptual difference in these costs since they both become part of the costs of production and must either be absorbed in profits or shifted to customers and, ultimately, to consumers. From the perspective of society, however, the difference between the tax payments and the costs of control is significant. In a full employment economy, allocation of resources for production of emissions control equipment implies a reduction in the production of other goods and services. The tax payments, however, are transfers of income from industry to government, and imply no reduction in production.

The total annualized costs to all major sources together are shown in figure 6. Since the tax induces emission control, the total costs of the tax increase at a decreasing rate.

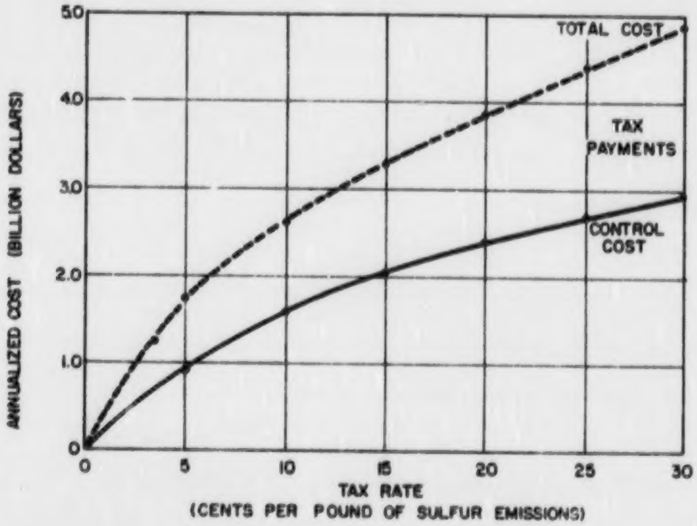

Figure 6. Total costs induced by a tax on the sulfur emissions from all major sources combined--1978 (Source: Research Triangle Institute).

3.6 Tax Revenues

From the perspective of government, the tax payments by the polluting sources are revenues. These revenues are shown in figure 7 for all tax rates under consideration. At a tax rate of 10 cents, revenues would be about $1 billion annually or about $5 per capita. A tax of 30 cents would almost double revenues from those projected for the 10-cent tax. It should be noted, however, that the net increase in government revenues would not be the full amount of the emissions tax since emissions tax payments would reduce the firm's income tax liability by the amount equal to the tax rate times the total emissions tax liability. For example, if the corporate tax rate were 50 percent, the net increase in government revenues would be one-half of the total emissions tax proceeds.

3.7 Cost-Benefit Analysis

Ideally, as discussed in chapter 2, the application of emissions taxes for environmental quality management would not be based on cost-effectiveness but rather on cost-benefit analyses. Data on the nature of the benefit

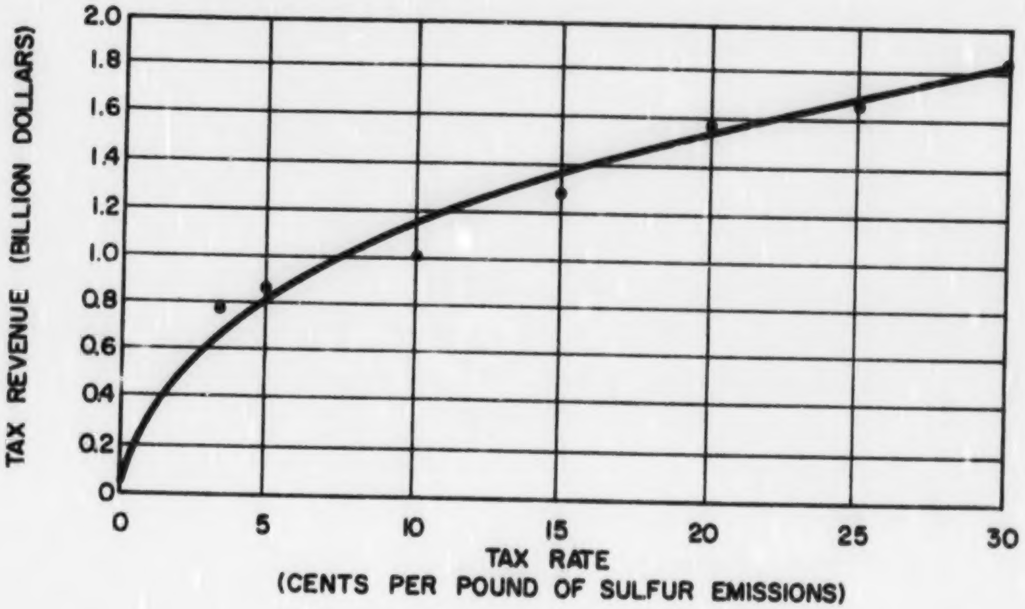

Figure 7. Tax revenues from a tax on sulfur emissions from all major sources combined--1978 (Source: Research Triangle Institute).

function for sulfur emissions reductions are currently quite incomplete. However, estimates developed from a recent compilation and evaluation of the damages of residential property, materials, health, and vegetation from the presence of sulfur oxides in the atmosphere for 1968 indicate that the national cost averaged about $500 per ton of sulfur*. The authors of that study point out a number of limitations in the data, but conclude: (1) these are the best estimates currently available, and (2) for the present it must be assumed that the marginal and average benefits (or avoidance of damages) are equal. Using their estimate for 1968 of $500 per ton and assuming that the damages in 1978 are the same per ton, a tax of 25 cents would equate the costs and benefits of control at the margin. It should be noted that the benefits would vary from region to region as would the costs.

3.8 Impacts on Consumer Prices

It is beyond the scope of this study to provide any extensive analysis of the likely incidence of the sulfur tax. However, a preliminary analysis is possible.

The effect of a tax on sulfur emissions (or, for that matter, of regulation on emissions) will be an increase in the marginal costs of production for every affected firm in the industry whose emissions are being taxed. Since the horizontal summation of the marginal cost curves of these firms yields the industry supply curve (assuming the absence of external economies or diseconomies and a perfectly competitive industry), the effect of a tax is to shift the industry supply curve upward and to the left. Assume, for the sake of expositional simplicity, that the sulfur tax implies a uniform increase (t) in the marginal costs of producing Q, an output whose production generates sulfur emissions. One can then depict the effect of the tax as an upward shift in the supply schedule of the subject industry by the constant amount of the uniform tax-induced increase (t) in marginal costs. The supply schedule shifts from S to S + t in figure 8. Since the price and output of Q are determined by the intersection of the supply and demand schedules, the sulfur tax would induce a reduction in output from Q_0 to Q_1, and an increase in the price per unit of Q from P_0 to P_1.

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*Larry Barrett and Thomas Waddell, Cost of Air Pollution Damage: A Status Report, Environmental Protection Agency, Research Triangle Park, N. C., 1973, p. 61.

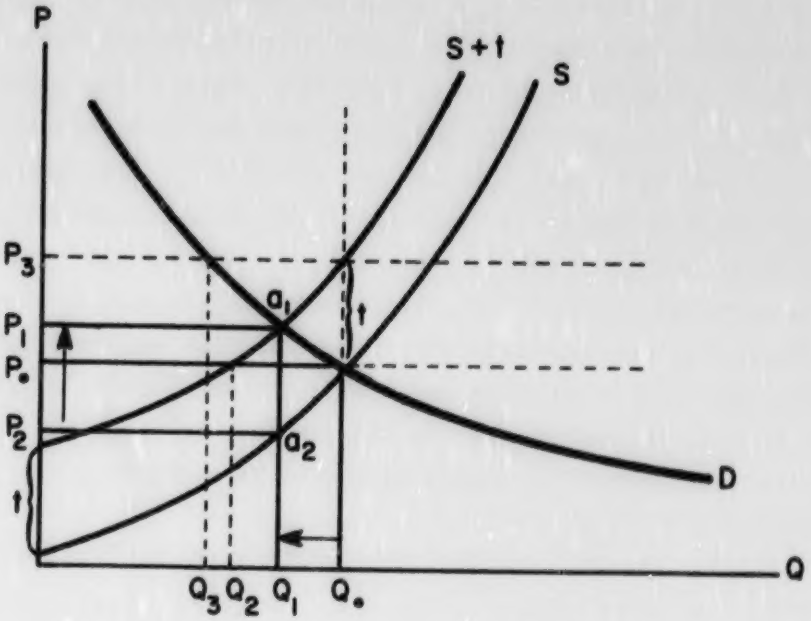

Figure 8. The incidence of a sulfur emissions tax.

The importance of this analytical device derives from the obvious fact that the percentage increase in the price of the product whose output generates pollution depends critically upon the slope of both the supply and demand schedules. The demand schedule, in general, will become more horizontal (vertical) according to whether there are (are not) good substitutes for Q and according to whether the product constitutes a large (small) share of the average consumer's budget. The supply schedule, on the other hand, becomes more horizontal (vertical) according to whether inputs to the production of Q can (cannot) be easily shifted into the production of other products.

As the supply and demand schedules are depicted in figure 8, only $(P_1 - P_0)/t$ of the uniform increase in the per unit cost of Q production is passed on to consumers. The remainder, $(P_0 - P_2)/t$, is absorbed by producers; they are forced to forego the profits (or rents) that would otherwise accrue to them. If all of the increase in costs is accounted for by tax payments, the government would collect emissions tax revenues equal to the area $P_1a_1a_2P_2$ during each period.

Now, observe the extreme possibilities. Assume that the demand schedule continues to be represented by D in figure 8 but that it is virtually impossible to shift inputs out of Q production. The result would be a vertical supply schedule at the quantity Q_0. All of the emissions tax-induced costs would be absorbed by producers as forfeited profits. The price would remain at P_0. At the opposite extreme, assume that all inputs to Q production are supplied to producers in unlimited quantities at constant prices (perfectly elastically supplied). The consequence is a horizontal supply schedule. All of the costs of the emissions tax would devolve onto the final consumers. Prices would rise by the full amount of the tax-induced costs (to P_3) and consumption would fall (to Q_3).

A similar analysis of extreme behavior in demand is possible by assuming the supply schedule remains stable at S and by allowing the demand schedule to vary in slope. If, for example, there are nearly perfect nonpolluting substitutes for Q, consumers will not tolerate any increase in its price; the demand schedule will be perfectly elastic (horizontal). Producers will have to absorb all of the cost imposed by the tax, and output will fall to Q_2 as the marginal producers of Q go out of business. On the other hand, if the consumer has no ready access to substitutes for Q or if Q is a very small share of his budget (so that price increases go virtually unnoticed), the demand schedule is likely to be perfectly inelastic (vertical) at Q_0. This would enable producers to shift the entire burden of the tax to consumers. The price of Q would rise to P_3 while the output would remain constant at Q_0.

An initial analysis of these price effects can be accomplished by assuming what, for consumers, is a worst-case situation--that the entire cost increase attributable to the tax is passed on to them. This analysis combines the assumption that inputs to the affected industry are relatively mobile (supply is elastic) while consumer preference for that product is relatively inflexible, in the face of price changes. Allowing these assumptions, RTI was able to adapt its previously developed model to project the consumer price increases implied by increases in industry production costs.

In a previous study for EPA*, RTI developed a model for projecting the impact on consumer prices of increases in industry costs. This model utilizes the 1963 national input-output table (at the 364 sector level) plus a disaggregated consumer demand sector with 80 subcategories of personal consumption expenditures.*

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*D. A. LeSourd and F. G. Bunyard, eds., Comprehensive Study of Specified Air Pollution Sources to Access the Economic Impact of Air Quality Standards, EPA contract No. 68-02-0088, Research Triangle Institute, Research Triangle Park, N. C., August 1972.

The limitations of input-output analysis are well known and the implications of using a 1963 structure of product to represent an economy 15 years hence are obvious and need not be further discussed here. Price increases may take many forms such as reductions in quality or service; they may also be distributed discriminately to different customers of the industry's products. Suffice it to say that the model can only provide a first approximation of what is a very complex and not well understood process. Nevertheless, taken in that light, the model does provide a useful appraisal of the possible price impacts of a tax on sulfur emissions.

Table 6 shows the initial price increases for selected tax rates, on a percentage basis using 1970 product prices as the base; these increases are projected for each of five sources assuming that they shift the entire cost of the tax in the form of higher product prices. All annualized industry costs associated with the tax or with pollution abatement were halved to account for the effect of government cost-sharing through the corporation tax structure. See appendix F.

Table 6. Projected initial price increases resulting from a tax on sulfur emissions (percent increase over 1970 average prices)

Source	Tax rate (cents per pound of sulfur emitted) 5	10	15	20	25	30
Steam-electric	2.2	3.4	4.2	4.9	5.0	6.2
Petroleum refining	0.1	0.2	0.3	0.4	0.5	0.6
Sulfuric acid production	2.6	4.0	4.5	4.9	5.2	5.5
Primary copper smelting	1.0	1.1	1.2	1.3	1.4	1.5
Primary zinc smelting	0.9	1.4	1.8	1.9	2.0	2.1
Primary lead smelting	0.7	0.8	0.9	1.1	1.2	1.3

Source: Research Triangle Institute.

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*This index is a Paasche-type measure of consumer price changes, since the current composition of expenditures is used to weight the components of the index.

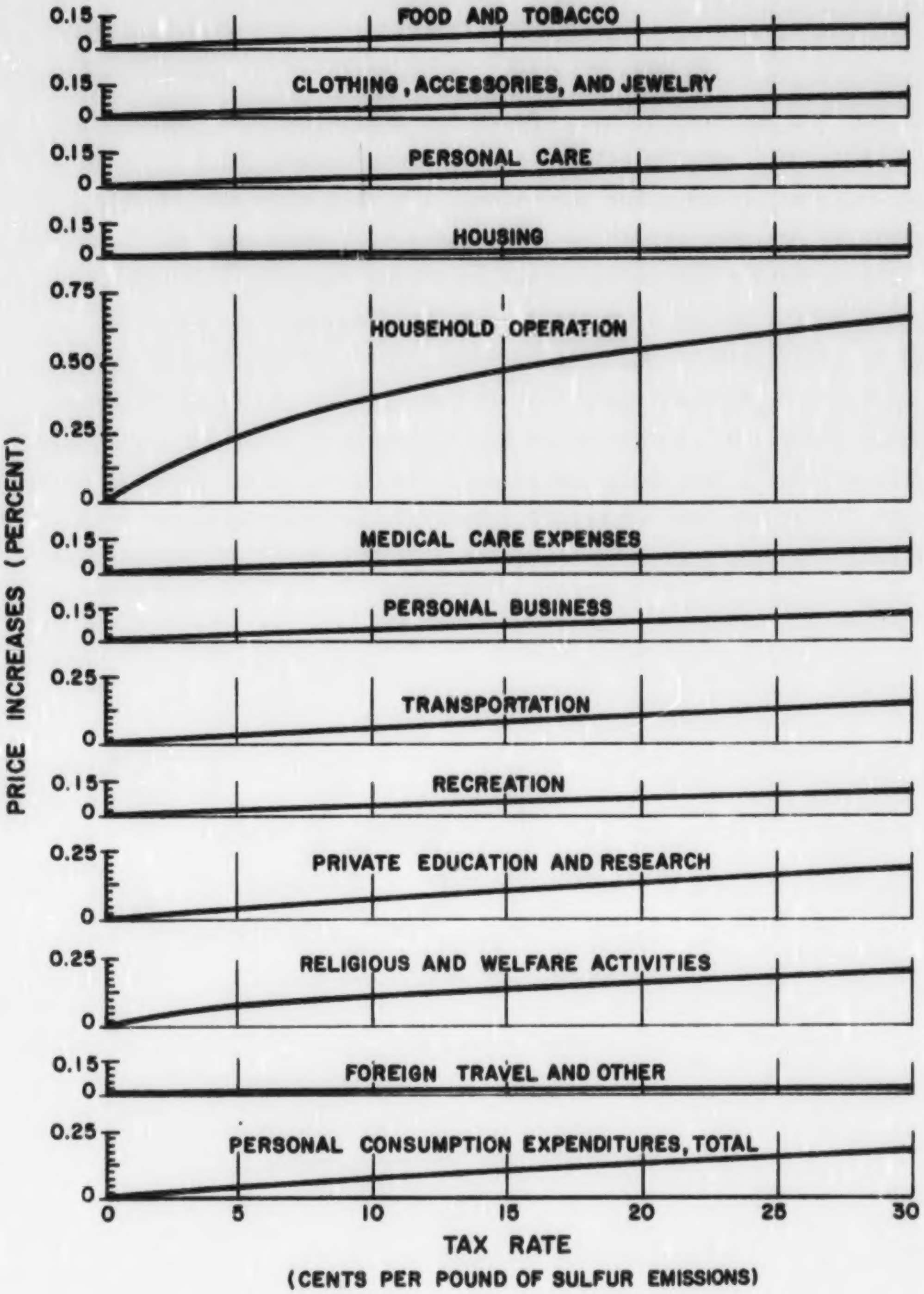

Figure 9. Projected impact on consumer prices of a tax on the sulfur emissions from all major sources--1978 (Source: Research Triangle Institute).

Figure 9 depicts the effect of the intermediate goods price increases (table 6) on final product prices. Among the six identified intermediate product categories, higher electricity prices would have the most significant impact on consumer prices. For the highest tax rate examined (30 cents), the increase in consumer prices would be about 0.15 percent (fig. 9, bottom panel). The percentage price increases in figure 9 are small relative to those in table 6 since the products in the table are only a few of the intermediate goods used to produce the final goods and services in the figure. The expenditure category that includes relatively more of these intermediate goods and that therefore would experience a larger percentage increase in prices is household operation. The other expenditure categories are affected to a much smaller extent. Overall, it seems apparent that the sulfur-tax-induced increases in consumer prices would not be substantial.

Chapter 4: SOURCE-BY-SOURCE ANALYSIS OF THE EFFECTIVENESS AND COSTS OF A TAX ON SULFUR EMISSIONS

4.1 Introduction

This chapter provides an analysis of the projected effectiveness and costs of a tax on sulfur emissions for each of the major sources examined in this study--steam-electric utilities, area sources, petroleum refineries, sulfuric acid plants, and primary nonferrous smelters. A discussion of the indirect impact of the tax on fuel demand and prices is also included.

Many of the control techniques for reducing sulfur emissions from the sources being examined in this study result in the recovery of sulfur or sulfuric acid.* If the market for sulfur or sulfuric acid proves to be sufficiently large to absorb the quantities recovered, revenues from such sales would lower control costs. The lower costs should encourage greater levels of control for a given tax rate. However, there are several cogent reasons for concluding that future prices for recovered sulfur and sulfuric acid will go below their currently depressed levels.† With only limited prospects of future markets for sulfur, some firms may actually face a dispoal problem (i.e., a negative price) with respect to their recovered sulfur. Therefore, for the industrial process sources (petroleum refineries; sulfuric acid producers; copper, lead, and zinc smelters), the sensitivity of the projected effectiveness and costs of the tax to changes in values of recovered sulfur and sulfuric acid is also provided.

Finally, because of the difficulty in accounting for all of the process and operating configurations that influence control costs, the sensitivity of the projected effectiveness and costs of the tax to alternative control cost estimates is also analyzed.

4.2 Steam-Electric Power Plants

Projections of the response of the nation's steam-electric power plants to a tax on sulfur emissions have been made on a utility-by-utility basis using the emissions and control data and the fuels availability data and price information shown in appendix A. The projected responses of all the nation's utilities have been summed to obtain industry totals. The resulting projections, however, are approximations that do not reflect all of the control alternatives nor fuel availabilities and transportation strategy costs among utilities. The omitted hardware strategies were generally those that are currently considered highly experimental and that are not currently expected to be available by 1978.

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*Sulfuric acid is about 33 percent elemental sulfur, by weight.

†See appendix E for further discussion on this topic.

4.2.1 Background

In 1968, combustion of fossil fuels by steam-electric utilities accounted for an estimated 50.6 percent of the estimated nationwide sulfur emissions from all sources.*

In 1970, installed steam-electric generating capacity of the 953 plants was 260,272.1 thousand kilowatts; actual generation was 1,220.1 billion kilowatthours.† An additional 269 billion kilowatthours were produced by hydroelectric nuclear generating stations. Utilities are either investor owned, publicly owned (non-Federal), federally owned, or owned by cooperatives. This industry is subject to comprehensive rate and service regulation on the part of governmental commissions at several levels of government.

4.2.2 Industry Growth

From 1957 through 1970, steam-electric-generated electricity increased an average of 7.4 percent annually. However, as shown in figure 10, growth has varied throughout the period.

Generation of electricity by steam-electric power plants is projected to increase about 3.6 percent annually between 1970 and 1978.‡ Actual generation is therefore projected to be about 1,631.0 billion kilowatthours.

4.2.3 Effectiveness

The response of the nation's steam-electric utilities to a tax on their emissions of sulfur has been projected for selected tax rates.

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*National Air Pollution Control Administration. Nationwide Inventory of Air Pollutant Emissions,--1968, Raleigh, N. C., August 1970.

†National Coal Association, Division of Economics and Statistics, Steam-Electric Plant Factors--1969, Washington, D. C., 1969, p. 118.

‡National Economic Research Associates, Inc., Fuels for the Electric Utility Industry, 1971-1985, Prepared for the Edison Electric Institute, New York, N. Y., August 1972.

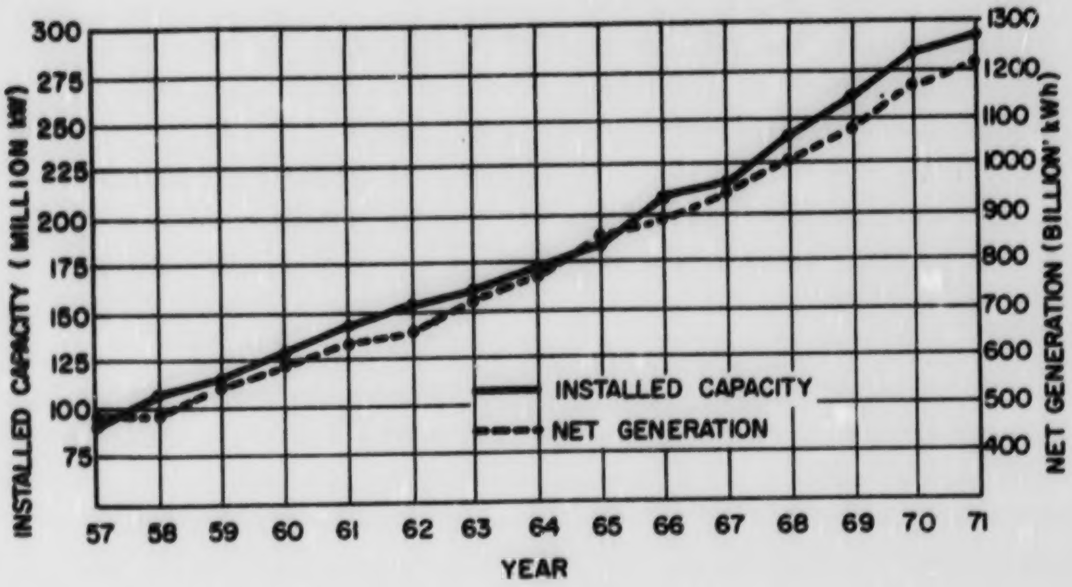

Figure 10. Steam-electric power plant trends
(Source: National Coal Association).

One considered control alternative used, magnesia base scrubbing, produces sulfur which can be sold to offset some control costs. It has been assumed that the recovered sulfur can be sold at $10 per ton, although, as discussed in appendix E, there is considerable uncertainty regarding the 1978 market value of sulfur. However, a brief analysis has confirmed that this value does not significantly alter the projected effectiveness and costs of a tax in the case of the steam-electric utilities.

Since sulfur emissions from steam-electric utilities are, in the absence of flue gas desulfurization, a function of the amount and sulfur content of the fuels consumed, projections of fuel demands, supplies, and prices are needed to project fuel utilization and emissions.

As discussed in appendix A, projecting long-run fuel supplies and price requires a knowledge of many technical, economic, and even political factors. This research has provided only an initial examination of how these factors may interrelate in 1978 with projected fuel demands to determine future fuels usage and the resulting emissions. Using fuels supply data as presented in appendix A for each major supplying region and for several fuel sulfur contents, these supplies have been allocated to utilities by establishing prices consistent with projected supplies. The future supplies of coal and domestic residual oil were assumed to grow at the maximum rates hypothesized by MITRE.* The supply of imported oil was assumed to be perfectly elastic at prices given in a recent study.† Gas was assumed to be available only to current users.

Within the model employed for this study, the demand for coal-supplied Btu's can be met by purchasing any one of 9 sulfur content coals from 19 producing regions. Residual oil demand can be met by purchasing any one of 5 sulfur contents from 12 origins, including imports. For gas demand, 1 sulfur content and 12 origins have been used. Prices at the mine or wellhead plus transportation costs equal the delivered prices at the utility. An estimate of minimum mine and wellhead prices from a previous study for EPA† provided initial selling prices for domestically produced fuels. In cases where these prices caused fuel demand to exceed supply, the prices were increased until fuel demand was less than or approximately equal to supply on a national basis. It is recognized that this procedure does not incorporate all of the sophistication desirable; yet within the more limited scope of this study, it does provide a reasonable basis for developing a structure of relative fuel prices by sulfur content and location.

Sulfur emissions from all steam-electric plants, assuming no additional controls other than those required by the New Source Performance Standards (a zero tax) are projected to be about 11 million tons in 1978 (see table 7). Coal burning accounts for 77 percent of these emissions. The remaining 23 percent is accounted for by residual oil combustion. The contribution by gas is negligible.

Utilities can control sulfur emissions by two general approaches--fuel switching‡ or installation of control equipment. As discussed in appendix A, the only fuel switching permitted is from coal to oil. Three control systems (dry limestone, wet limestone, and magnesia scrubbing) are assumed available. The utilities are assumed to minimize total costs, defined as the sum of control costs, delivered fuel premiums, and tax payments. This assumption

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*MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972.

†Battelle Memorial Institute, EPA Energy Quality Model, September 1972.

‡For this study, "fuel switching" means substitution of a fuel of a different sulfur content from that projected in the absence of a tax. It may be either the same type of fuel as purchased without a tax or an alternative fuel.

Table 7. Projected sulfur emissions from steam-electric utilities--1978*

Source	Annual sulfur emissions (thousand tons of sulfur)
Coal combustion	8,781
Oil combustion	2,615
Gas combustion	0
Total	11,396

*Assuming only controls required by New Source Performance Standards.

Source: Research Triangle Institute.

follows the conclusions of a recent EPA-sponsored study which concluded that, for a number of reasons, utilities can be expected to follow cost-minimizing behavior.*

The projected response of all steam-electric utilities to the sulfur tax for selected tax rates are provided in table 8 and in figure 11. Control costs and fuel prices by sulfur content and origin as used for this analysis are presented in appendix A. The results displayed here indicate some important results. Although reductions in emissions are induced by higher tax rates throughout the range of tax rates considered, only comparatively small additional reductions are induced at rates above 15 cents per pound. This exponential relationship between emissions tax rates and emissions reductions implies, for example, that a tax of 15 cents would induce emissions reductions 46 percent greater than those at a 5-cent tax rate. Doubling the tax to 30 cents would precipitate only a 9-percent increase in reductions over those that would occur at a 15-cent tax rate.

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*Institute of Public Administration, Governmental Approaches to Air Pollution Control: A Compendium and Annotated Bibliography, Submitted to Office of Air Programs, Environmental Protection Agency, July 15, 1971 (NTIS: PB-203 111).

Table 8. Projected response of all steam-electric power plants national tax on sulfur emissions--1978 (recovered sulfur valued at $10 per ton)

Emissions source	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annualized cost (thousands)	Annualized control cost (thousands)	Annual tax payment (thousands)
Tax rate: 5 cents per pound of sulfur emissions					
Coal combustion	4,731.4	5,478.7	$1,056,152	$ 582,990	$473,163
Oil combustion	427.4	758.3	115,635	72,891	42,744
Gas combustion	0.2	0.0	21	0	21
Total from all sources	5,159.0	6,237.0	$1,171,808	$ 655,881	$515,928
Tax rate: 10 cents per pound of sulfur emissions					
Coal combustion	2,675.8	7,534.4	$1,595,971	$1,060,758	$535,214
Oil combustion	285.8	899.8	178,648	121,472	57,176
Gas combustion	0.2	0.0	42	1	42
Total from all sources	2,961.8	8,434.2	$1,774,661	$1,182,231	$592,432
Tax rate: 15 cents per pound of sulfur emissions					
Coal combustion	2,055.6	8,154.6	$1,986,655	$1,369,909	$616,749
Oil combustion	221.9	963.6	228,350	161,747	66,604
Gas combustion	0.2	0.0	64	0	64
Total from all sources	2,277.7	9,118.2	$2,215,069	$1,531,656	$683,417
Tax rate: 20 cents per pound of sulfur emissions					
Coal combustion	1,746.3	8,464.0	$2,316,748	$1,618,123	$698,625
Oil combustion	201.7	983.7	272,855	192,172	80,684
Gas combustion	0.2	0.0	85	0	85
Total from all sources	1,948.2	9,447.7	$2,589,688	$1,810,295	$779,394
Tax rate: 25 cents per pound of sulfur emissions					
Coal combustion	1,413.1	8,797.3	$2,596,415	$1,889,803	$706,614
Oil combustion	186.2	999.2	315,361	222,245	93,116
Gas combustion	0.2	0.0	106	0	106
Total from all sources	1,599.5	9,796.5	$2,911,882	$2,112,048	$799,836
Tax rate: 30 cents per pound of sulfur emissions					
Coal combustion	1,253.6	8,956.8	$2,830,658	$2,078,415	$752,244
Oil combustion	178.3	1,007.1	355,590	248,577	107,013
Gas combustion	0.2	0.0	127	0	127
Total from all sources	1,432.1	9,963.9	$3,186,375	$2,326,992	$859,384

Source: Research Triangle Institute.

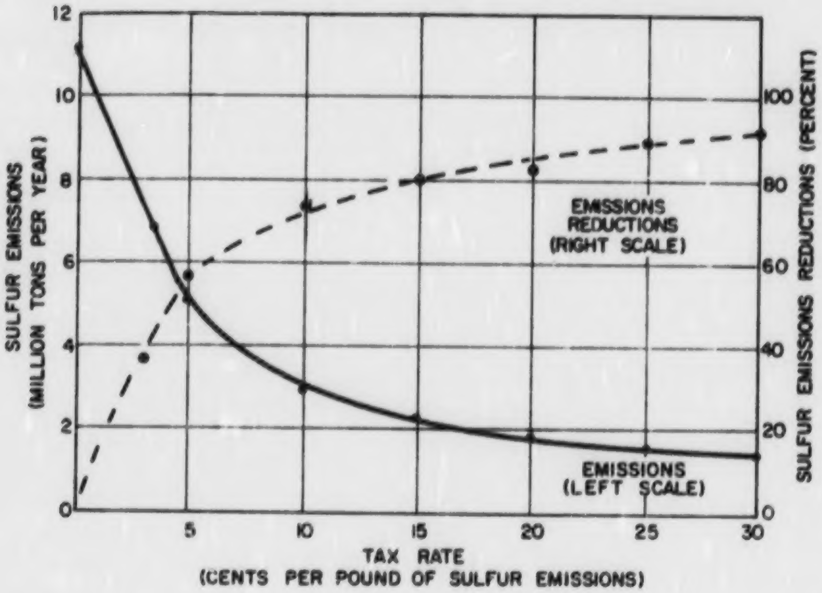

Figure 11. Effectiveness of a tax on sulfur emissions: steam-electric power plants--1978 (Source: Research Triangle Institute).

Table 9 shows the projected percentage distribution of power producing unit's fuel and flue gas cleaning hardware choices in response to increments in the sulfur emissions tax. As the tax is increased, the percentage of producing units that use coal steadily declines (from more than 40 percent with a 5-cent tax to about 23 percent with a 30-cent tax). Although relatively small increases in control hardware are induced among coal-burning plants, large increments are projected for the dry limestone scrubbing systems among oil-burning plants.

Table 10 provides data for the projected distribution of fuel demands by sulfur contents. The table shows the heating values (trillion Btu's) that are projected to derive from domestic and imported residual oil and from domestically produced coal. Bearing in mind that the simulation model presumed unlimited supplies of foreign residual oils at the prices given in appendix A, the reader will note the substantial shift by power plants away from coal to residual oil in the presence of increasing emissions tax rates. For example, at a zero tax rate, coal would constitute more than 76 percent of the total coat- and oil-heat input to power plant boilers; at a 15-cent tax rate, about 48 percent; and at a 30-cent tax rate, only

Table 9. Effects of the sulfur emissions tax on the distribution of flue gas desulfurization choices for steam-electric power producing units*

	Tax rate (cents per pound of sulfur emissions)					
	5	10	15	20	25	30
Coal combustion						
No hardware	35.8	28.1	23.3	21.9	19.2	17.2
Dry limestone	0.9	1.9	2.4	1.8	1.6	1.4
Wet limestone	0.1	0.0	0.0	0.0	0.0	0.0
Magnesia base	3.6	3.7	3.7	4.0	4.2	4.3
Total	40.4	33.9	29.4	27.7	25.0	22.9
Oil combustion						
No hardware	53.4	58.9	56.4	52.1	49.7	47.4
Dry limestone	3.1	4.3	11.1	17.1	22.2	26.6
Wet limestone	0.1	0.1	0.1	0.1	0.1	0.0
Magnesia base	3.0	3.0	3.0	3.0	3.0	3.1
Total	59.6	66.3	70.6	72.3	75.0	77.1

*Generally, boiler(s) with a common size, age, and fuel were treated as the producing unit. For small plants, data inadequacies required that the entire plant be treated as the producing unit.

Note: At a zero tax rate, no additional flue gas desulfurization would be induced.

Source: Research Triangle Institute.

Table 10. Distribution of steam-electric utilities' demand for coal and residual oil by sulfur content--1978 (trillion Btu)

	Coal										Residual oil						
	Sulfur content (percent)									Totals	Sulfur content (percent)					Totals	Implied† imports
	0.7	0.9	1.3	1.8	2.3	2.8	3.3	3.8	5.0		0.4	0.6	1.2	2.3	3.0		
Projected maximum domestic supply (trillion Btu)	2.4	2.6	1.2	1.8	1.1	1.2	2.6	2.8	1.4	17.1	1.1	0.7	0.3	0.4	0.1	2.6	--
Tax rate*																	
0	0.0	0.6	0.0	0.2	0.7	1.4	2.6	2.9	1.4	9.8	0.0	0.1	0.1	1.2	1.6	3.0	0.4
5	0.6	1.1	1.0	0.1	2.0	0.8	0.1	0.9	1.4	8.0	0.1	1.1	2.2	0.7	0.7	4.8	2.2
10	1.6	0.9	1.6	0.1	0.4	0.1	0.1	0.9	1.4	7.1	0.4	3.5	1.0	0.3	0.6	5.8	3.2
15	1.7	1.0	1.0	0.1	0.0	0.1	0.1	2.1	0.1	6.2	0.9	4.8	0.0	0.4	0.5	6.6	4:0
20	1.8	0.6	0.4	0.0	0.1	0.2	0.2	2.1	0.1	5.5	1.3	5.0	0.0	0.4	0.5	7.2	4.6
25	1.6	0.2	0.0	0.0	0.1	0.3	0.3	2.1	0.0	4.6	3.1	4.1	0.0	0.4	0.5	8.1	5.5
30	0.9	0.2	0.0	0.0	0.3	0.8	0.8	1.2	0.0	4.2	3.9	3.9	0.0	0.4	0.5	8.7	6.1

*Cents per pound of sulfur emissions.

†These are minimum amounts since they do not include the projected residual oil consumption by area sources.

Source: Research Triangle Institute.

33 percent. The demand for imported residual oil is projected in the far right-hand column of table 10. At intermediate tax rates, these values are comparable to current imports of residual oil, for all uses, which are currently on the order of 3.5 trillion Btu's; this implies about a 60-percent increase in residual oil imports by 1978 if all such imports are diverted for use in power generation. In section 4.2.5 the assumption of fixed oil prices is relaxed. The sensitivity analysis performed there indicates the extreme importance of those prices in determining the distribution of demand.

4.2.4 Costs

The total outlays of the steam-electric utilities were shown in table 8 for selected tax rates. Figure 12 displays the allocation of the costs between emissions tax payments and control costs. The latter include both flue gas desulfurization costs and fuel switching premiums. In absolute terms, total tax payments rise from about $515 million at a 5-cent tax rate to about $860 million at a 30-cent tax rate. However, as a percentage of total emission-control-related costs, the share accounted

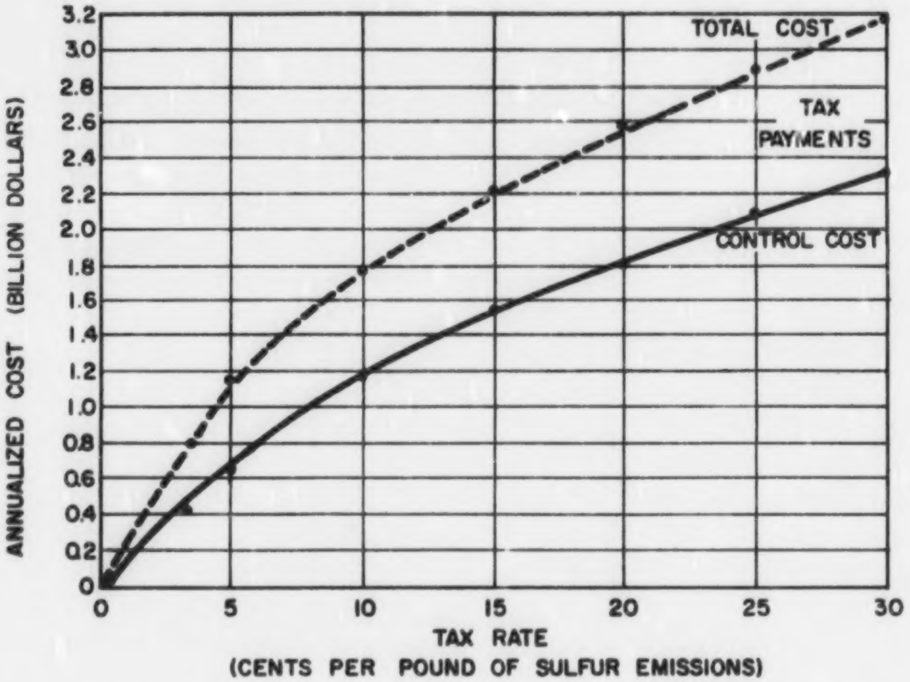

Figure 12. Total costs induced by a tax on sulfur emissions: steam-electric power plants--1978 (Source: Research Triangle Institute).

for by taxes falls from about 44 percent to about 27 percent at tax rates of 5 and 30 cents per pound, respectively. Considering that a 30-cent tax is projected to induce about a 90-percent reduction in emissions (fig. 11) from power plants, this result implies that a policy goal of sulfur emissions reductions of that magnitude can be achieved at only a 27-percent penalty above minimum control costs to the average firm. To society as a whole, there would be no penalty at all since the taxes are merely transfers. Consequently, to the extent that regulation would achieve 90-percent reductions less efficiently than a tax (it cannot be more efficient), all of the additional costs (of achieving that goal) above an estimated $2.3 billion can be considered deadweight losses.

Table 11 gives the distribution of control costs between those for stack gas cleaning and those for fuel switching as the tax rate varies. For a zero tax rate, no additional control is induced, of course. At low tax rates, the distribution is fairly equal; at high tax rates the costs of flue gas cleaning become the larger share since many more utilities are induced to use dry limestone and magnesia base scrubbing systems. Fuel switching costs include net changes not only in the f.o.b. cost of low sulfur fuels but also in transportation expenses. At positive tax rates, the transportation costs are actually projected to be somewhat lower than those with a zero tax since oil (to which utilities are induced to shift,

Table 11. Percentage distribution of control costs

Tax rate*	Flue gas desulfurization	Fuel switching†	Total
5	50.7	49.3	100.0
10	47.4	52.6	100.0
15	51.3	48.7	100.0
20	57.8	42.2	100.0
25	58.9	41.1	100.0
30	62.0	38.0	100.0

*Cents per pound of sulfur emissions.

†These costs are delivered fuel costs at the utility.

Source: Research Triangle Institute.

with the tax and oil prices used) has lower transportation costs per Btu than coal, for most utilities. It is likely, however, that the fuel switching costs are underestimated at high tax rates, for if the supply of imported oil is not assumed to be perfectly elastic, competitive bidding for limited supplies will increase the price of oil. This possibility is analyzed further in section 4.2.5 below.

Figure 13 gives the average cost increases per kilowatthour, as the tax rate is increased. As a percentage of current average electricity costs (1.6 cents/kWh), a 5-cent tax would induce a 4.3-percent increase in average costs; a 15-cent tax, an 8.7-percent increase; and a 30-cent tax, about a 12-percent increase. These values are based on the assumption that the demand for electricity is perfectly inelastic and do not include the effects of the corporate income tax.

4.2.5 Sensitivity Analysis

The projected effectiveness and costs of a tax on the sulfur emissions of steam-electric utilities are expected to be strongly influenced by fuel availabilities and prices. As discussed above, using projections of the fuel prices without a tax, and then applying a tax, many utilities are

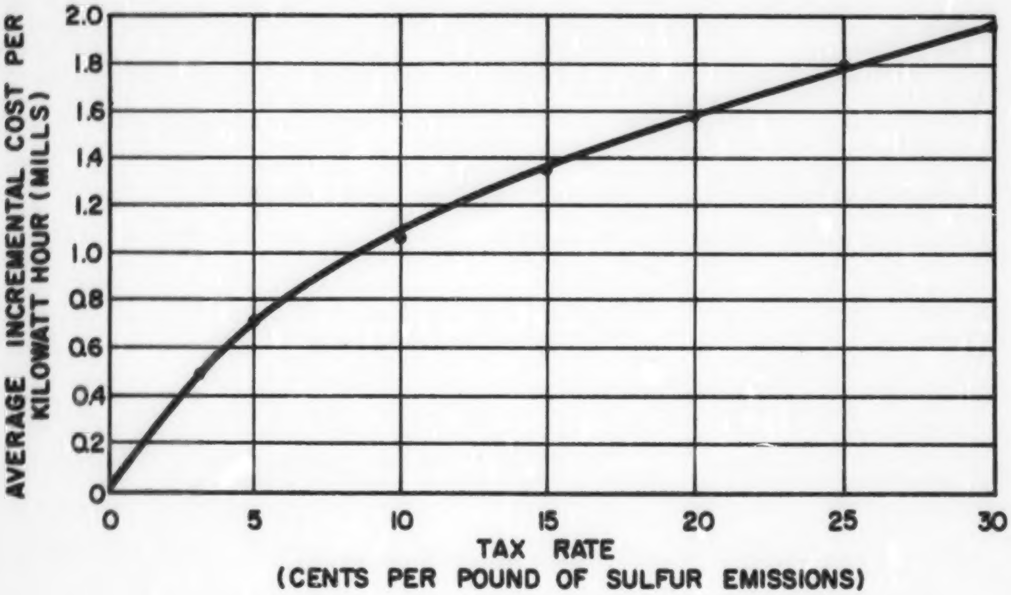

Figure 13. Average total (control cost plus tax payments) incremental costs per kilowatthour induced by a tax on sulfur emissions: steam-electric power plants--1978 (Source: Research Triangle Institute).

induced to switch from coal to oil to meet their fuel demands at minimum cost. However, such switching will place pressure not only on domestic oil supplies but also on imports. (See appendix A for preliminary estimates of these quantities.) For example, at a tax of only 5 cents, all of the projected supplies of domestic residual oil would be purchased by steam-electric utilities. However, these supplies would provide only two-thirds of demand; the remainder would have to be imported. At higher tax rates, higher imports of oil are required. Furthermore, this assumes that all residual oils are allocated to steam-electric utilities. Industrial and commercial sources are also consumers of residual oil. In 1978, their coal and residual oil requirements are expected to total about 4.1 trillion Btu's. The distribution of their consumption between the two fuels will also depend on relative fuel prices.

All oil prices were increased 20 and then 40 percent to examine the sensitivity of both emissions reductions and total control costs and tax payments to these higher oil prices. The results, shown in table 12, indicate that the oil price increases reduce the projected effectiveness of the tax by the largest percentage increase in emissions at a tax rate of 20 cents; i.e., emissions are about 20 and 29 percent higher when oil prices rise by 20 and 40 percent, respectively. To either side of this rate, the impacts are less (measured as a percentage of emissions) but, nevertheless, still significant. Total emission-control-related costs increase most at low tax rates with the percentage increases tapering off slightly as the tax rate increases.

Besides inducing a general shift toward coal, the increases in oil prices particularly encourage low-sulfur coal consumption. Table 13

Table 12. Sensitivity of effectiveness and total cost of tax on sulfur emissions to residual fuel oil prices: steam-electric power plants--1978

Change in all oil prices (percent)	Change in emissions (percent)						Change in total cost (percent)						Change in annualized control cost (percent)					
	Tax rate (cents per pound of sulfur emissions)						Tax rate (cents per pound of sulfur emissions)						Tax rate cents per pound of sulfur emissions)					
	5	10	15	20	25	30	5	10	15	20	25	30	5	10	15	20	25	30
+20	12.2	15.0	18.5	20.4	16.8	7.9	19.7	18.6	17.8	17.3	17.1	16.6	25.6	20.4	17.4	15.9	17.2	19.8
+40	15.8	20.7	26.5	29.3	20.5	14.4	29.3	26.0	24.7	24.1	23.4	22.8	40.0	28.9	24.0	21.9	24.4	25.9

*Control costs plus tax payments.

Source: Research Triangle Institute.

Table 13. Distribution of steam-electric utilities' demand for coal and residual oil by sulfur content with increased prices for residual oil--1978 (trillion Btu)

	Coal										Residual oil						
	Sulfur content (percent)									Totals	Sulfur content (percent)					Totals	Implied† imports
	0.7	0.9	1.3	1.8	2.3	2.8	3.3	3.8	5.0		0.4	0.6	1.2	2.3	3.0		
Projected maximum domestic supply (trillion Btu)	2.4	2.6	1.2	1.8	1.1	1.2	2.6	2.8	1.4	17.1	1.1	0.7	0.3	0.4	0.1	2.6	--
Tax rate*	Increase in all oil prices of 20 percent																
0	0.0	0.6	0.0	0.2	0.8	1.5	2.2	3.3	2.3	10.9	0.0	0.0	0.0	0.8	1.2	2.0	0.0
5	0.7	1.3	1.1	1.2	2.9	0.8	0.1	0.4	2.2	10.7	0.0	0.7	0.3	0.3	0.8	2.1	0.0
10	2.2	1.5	3.2	0.3	0.4	0.1	0.0	0.5	2.1	10.3	0.2	1.2	0.3	0.4	0.3	2.4	0.0
15	2.3	2.4	1.7	0.1	0.0	0.1	0.0	1.8	0.8	9.2	0.4	2.4	0.1	0.4	0.3	3.6	1.0
20	3.4	1.4	1.2	0.0	0.1	0.3	0.1	2.4	0.1	9.0	0.6	2.5	0.0	0.4	0.3	3.8	1.2
25	3.9	1.2	0.0	0.0	1.6	0.4	0.1	2.5	0.0	9.7	0.6	1.7	0.0	0.5	0.2	3.0	0.4
30	3.6	0.6	0.1	0.0	2.0	0.8	0.4	1.7	0.0	9.2	1.0	1.8	0.0	0.5	0.3	3.6	1.0
	Increase in all oil prices of 40 percent																
0	0.0	0.6	0.0	0.2	0.8	1.5	2.2	3.5	2.3	11.1	0.0	0.0	0.0	0.9	0.7	1.6	0.0
5	0.7	1.3	1.2	1.5	3.0	0.8	0.1	0.4	2.2	11.2	0.0	0.4	0.0	0.5	0.7	1.6	0.0
10	2.5	1.5	3.4	0.6	0.4	0.1	0.0	0.5	2.1	11.1	0.0	0.7	0.1	0.6	0.3	1.7	0.0
15	3.9	2.4	1.9	0.2	0.0	0.1	0.0	1.8	0.8	11.1	0.1	0.7	0.1	0.4	0.2	1.5	0.0
20	5.2	1.4	1.4	0.0	0.1	0.3	0.1	2.5	0.1	11.1	0.2	0.8	0.0	0.5	0.1	1.6	0.0
25	4.9	1.3	0.0	0.0	1.7	0.5	0.1	2.6	0.0	11.1	0.4	0.8	0.0	0.6	0.1	1.8	0.0
30	5.0	0.6	0.1	0.0	2.2	0.8	0.4	1.7	0.0	10.8	0.4	0.9	0.0	0.6	0.1	2.0	0.0

*Cents per pound of sulfur emissions.

†These are minimum amounts since they do not include the projected residual oil consumption by area sources.

Source: Research Triangle Institute.

displays those projected shifts in the presence of 20 and 40 percent oil price increases. Table 14 is analogous to table 9 in that it shows the projected percentage distribution of fuel and flue gas desulfurization choices for power producing units. Compared to the producers' fuel choices under the benchmark prices, the number of coal consuming units is markedly higher, particularly at higher tax rates. Furthermore, the percentages of units using control hardware rise substantially. The most notable increases occur in the addition of dry limestone scrubbers to coal burning boilers.

4.3 Industrial, Commercial, and Residential Space Heating

Projections of the consumption of fossil fuels in industrial, commercial, and residential space heating applications have been made on a State-by-State basis using the emissions and control cost data shown in appendix A. These sources are generally referred to as "area sources" because of the geographically diffused nature of their emissions and because of the difficulty of identifying individual emissions sources. Because of these limited data and of the diversity of size among these industrial, commercial, and residential space heating sources, this analysis provides only a very preliminary examination of the effectiveness and costs of a tax on the sulfur emissions from these area sources. Further, for the same reasons, no sensitivity analysis of the response of the area sources to higher residual oil prices has been included. However, as compared to steam-electric abilities, area sources have fewer control options and, therefore, may reasonably be expected to show larger changes in emissions and total costs than those projected for utilities.

4.3.1 Background

In 1968, industrial, commercial, and residential space heating accounted for 22.8 percent of the estimated nationwide sulfur emissions from all sources.* Because the consumption of residual oil and coal (bearing relatively more sulfur than distillate oil and gas) is concentrated in the industrial and commercial space heating sectors, the predominant share of those emissions can reasonably be attributed to those sources. Table 15 shows the distribution of fuel consumption patterns in 1970, by sources; the reported values confirm the asserted importance of nonresidential sources in the consumption of relatively higher sulfur bearing fuels.

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*National Air Pollution Control Administration, Nationwide Inventory of Air Pollutant Emissions--1968, Raleigh, N. C., August 1970.

Table 14. Effects of residual oil price increases on the percentage distributions of flue gas desulfurization choices for steam-electric power producting units*

	Tax rate (cents per pound of sulfur emissions					
	5	10	15	20	25	30
	Increase in all oil prices of 20 percent†					
Coal combustion						
No hardware	46.3	42.3	37.4	35.9	32.6	29.3
Dry limestone	1.1	2.7	4.7	4.7	5.9	6.7
Wet limestone	0.1	0.0	0.0	0.0	0.0	0.0
Magnesia base	4.1	4.2	4.2	4.6	5.1	5.8
Total	51.6	49.2	46.3	45.2	43.6	41.8
Oil combustion						
No hardware	42.5	43.9	43.1	39.7	37.4	35.8
Dry limestone	3.4	4.2	7.9	12.4	16.3	19.8
Wet limestone	0.1	0.1	0.1	0.1	0.1	0.0
Magnesia base	2.5	2.6	2.6	2.6	2.6	2.6
Total	48.5	50.8	53.7	54.8	56.4	58.2
	Increase in all oil prices of 40 percent†					
Coal combustion						
No hardware	48.7	46.9	44.1	43.0	39.8	36.7
Dry limestone	1.2	3.0	5.4	5.8	7.8	9.5
Wet limestone	0.1	0.1	0.1	0.1	0.1	0.1
Magnesia base	4.2	4.2	4.3	4.7	5.4	6.1
Total	54.2	54.2	53.9	53.6	53.1	52.4
Oil combustion						
No hardware	39.7	38.6	36.5	33.0	30.3	28.4
Dry limestone	3.6	4.7	7.1	10.9	14.2	16.7
Wet limestone	0.0	0.0	0.0	0.0	0.0	0.0
Magnesia base	2.5	2.5	2.5	2.5	2.5	2.5
Total	45.8	45.8	46.1	46.4	47.0	47.6

*Generally, boiler(s) with a common size, age, and fuel were treated as the producing unit. For small plants, data inadequacies required that the entire plant be treated as the producing unit.

†Over the values presented in appendix A.

Source: Research Triangle Institute.

Table 15. Area source fuel consumption--1970

Source	Coal (thousand tons)	Residual oil (thousand barrels)	Distillate oil (thousand barrels)	Gas (million cubic feet)
Residential	---	---	447,691	3,206,100
Industrial	210,552	44,190	83,490	2,664,100
Commercial	13,557	73,650	113,812	1,035,900
Total	224,109	117,840	644,993	6,906,100

Source: Research Triangle Institute.

4.3.2 Industry Growth

The growth in the consumption of fossil fuels by these space heating units is expected to follow broad demographic and economic trends. For residential sources, growth was projected to follow the growth in population projected for each State as projected by the Department of Commerce.* For commercial and industrial sources, growth was projected to follow the overall national growth in employment as projected by the Bureau of Labor Statistics.†

4.3.3 Effectiveness

The input demand response of space heating sources to a tax on their sulfur emissions was projected for several tax rates. As discussed in appendix A, the only control alternative permitted is switching to lower sulfur coals or residual oils by the industrial and commercial sources; residential sources are assumed to remain committed to the fuels presently used; viz., distillate oil and natural gas.

It is likely that flue gas cleaning could be employed by some of the larger industrial and commercial sources; however, the lack of data on these sources precluded inclusion of this alternative in this study. If flue gas cleaning is likely, then the effectiveness of the tax would be greater and the total cost less than projected.

Sulfur emissions from area sources, assuming no controls, are projected to be about 5.7 million tons in 1978 (see table 16). The bulk of emissions would come from industrial sources, which would account for 78 percent of

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*Survey of Current Business, Volume 52, Number 4, April 1972.

†U. S. Department of Labor, Bureau of Labor Statistics, Patterns of U. S. Economic Growth, BLS Bulletin 1672, Washington, D. C.: U.S. Government Printing Office, 1970.

Table 16. Projected sulfur emissions from area sources--1978*

Source	Annual sulfur emissions (thousand tons of sulfur)
Residential	154
Industrial	4,490
Commercial	1,115
Total	5,759

*Assuming no controls.

Source: Research Triangle Institute.

the total, and commercial sources, projected to generate 20 percent of total emissions.

The projected responses of all area sources to the sulfur tax for selected tax rates are provided in table 17. Reductions in emissions from area sources are projected to increase over the entire range of tax rates considered here. However, the rate of increase falls precipitously above a tax rate of 10 cents per pound of sulfur emissions. For example, a tax rate of 10 cents per pound would induce emissions reductions that are 48 percent greater than those at a 5-cent tax rate. Tripling the tax rate to 30 cents per pound would encourage only an additional 11 percent in emissions reductions compared to those that are projected at a 10-cent tax rate. That sharply exponential response to changes in the tax rate is shown graphically in figure 14.

Table 18 summarizes the demand for coal and residual oil by the fossil fuel combustion sources considered in this report (steam-electric utilities and area sources). The reader is reminded again that these data are of a preliminary nature and based on assumptions as described above and in appendix A. The data in table 18 do show, however, rough magnitudes of the demand responses for several tax rates at the assumed fuel prices. At these prices, higher tax rates (which are inducing substantial emissions reductions) are placing significant pressures on oil supplies, especially imports. If these supplies are not forthcoming at the assumed prices due to an upward sloping supply curve for imported residual oil and/or curtailment of shipments from a major source for political or other purposes, the

Table 17. Projected response of all area sources to a national tax on sulfur emissions--1978

Emissions source	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control cost (thousands)	Annual tax payment (thousands)
Tax rate: 5 cents per pound of sulfur emissions					
Residential	153.5	0.0	$ 15,350	$ 0	$ 15,350
Industrial	2,203.0	2,206.3	358,925	138,620	220,306
Commercial	498.2	616.5	92,222	42,406	49,816
Total from all sources	2,854.7	2,822.8	$466,497	$181,026	$285,472
Tax rate: 10 cents per pound of sulfur emissions					
Residential	153.5	0.0	$ 30,701	$ 0	$ 30,701
Industrial	1,063.9	3,345.4	499,202	286,416	212,786
Commercial	276.9	837.8	124,362	68,975	55,387
Total from all sources	1,494.3	4,183.2	$654,265	$355,391	$298,874
Tax rate: 15 cents per pound of sulfur emissions					
Residential	153.5	0.0	$ 46,051	$ 0	$ 46,051
Industrial	959.5	3,449.9	598,975	311,142	287,835
Commercial	268.1	846.6	151,621	71,202	80,420
Total from all sources	1,381.1	4,296.5	$796,647	$382,344	$414,306
Tax rate: 20 cents per pound of sulfur emissions					
Residential	153.5	0.0	$ 61,401	$ 0	$ 61,401
Industrial	956.4	3,452.9	694,752	312,177	382,576
Commercial	267.3	847.4	178,373	71,469	106,904
Total from all sources	1,377.2	4,300.3	$934,526	$383,646	$550,881
Tax rate: 25 cents per pound of sulfur emissions					
Residential	153.5	0.0	$ 76,751	$ 0	$ 76,751
Industrial	747.8	3,661.5	780,574	406,640	373,934
Commercial	213.9	900.7	202,568	95,574	106,995
Total from all sources	1,115.2	4,562.2	$1,059,893	$502,214	$557,680
Tax rate: 30 cents per pound of sulfur emissions					
Residential	153.5	0.0	$ 92,101	$ 0	$ 92,101
Industrial	685.1	3,724.2	850,254	439,166	411,088
Commercial	192.3	922.4	222,351	106,987	115,365
Total from all sources	1,030.9	4,646.6	$1,164,706	$546,153	$618,554

Source: Research Triangle Institute.

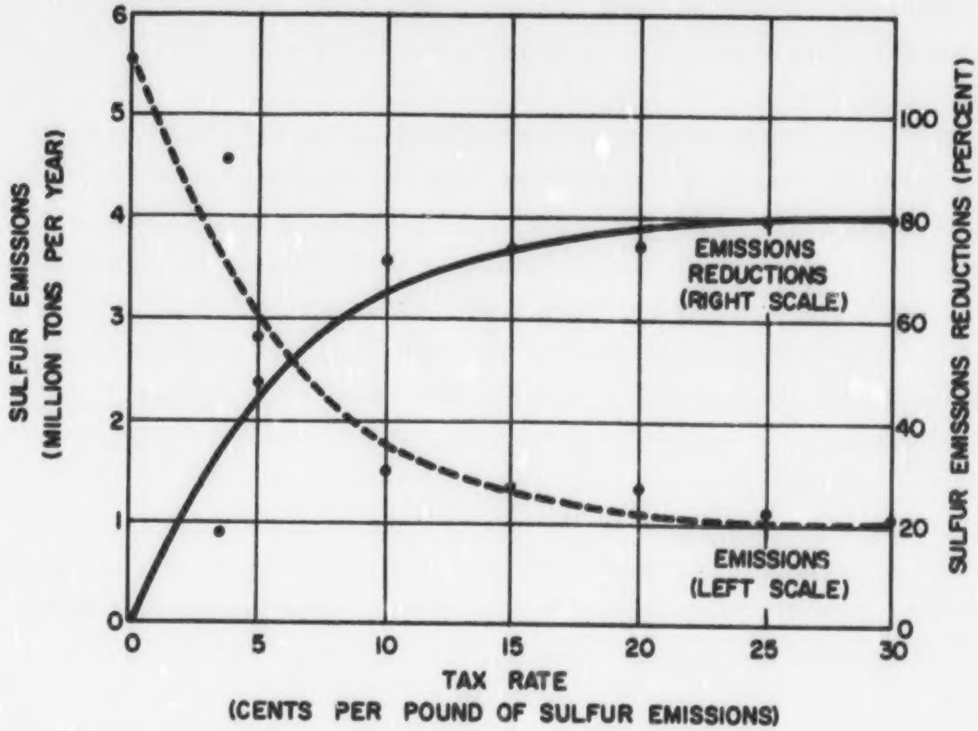

Figure 14. Effectiveness of a tax on sulfur emissions: area sources--1978 (Source: Research Triangle Institute).

Table 18. Distribution of the combined demand of steam-electric utilities and area sources for coal and residual oil--1978

	(trillion Btu)						
	Coal demand			Residual oil demand			
Tax rate	Utilities	Area sources	Totals	Utilities	Area sources	Totals	Implied imports
0	1.4	9.8	11.2	2.7	3.0	5.7	3.1
5	1.1	8.0	9.1	3.0	4.8	7.8	5.2
10	0.7	7.1	7.8	3.4	5.8	9.2	6.6
15	0.2	6.2	6.8	3.9	6.6	10.5	7.9
20	0.2	5.5	5.7	3.9	7.2	11.1	8.5
25	0.2	4.6	4.8	3.9	8.1	12.0	9.4
30	0.2	4.2	4.4	3.9	8.7	12.6	10.0

Source: Research Triangle Institute.

effectiveness of the tax would be reduced and the cost increased over that projected here. It should be noted, however, that under regulatory approaches to achieving emissions reductions, cost increases would also occur.

4.3.4 Costs

The total cost by the area sources are shown in table 17 and figure 15. The broken curve in figure 15 incorporates both tax payments and fuel switching premiums. The costs for residential sources increase linearly with higher tax rates since no fuel switching or emissions control options for those sources are considered in the simulation model. However, the total cost function for all area sources combined increases at a decreasing rate since emissions control among industrial and commercial sources is induced by the tax.

4.4 Petroleum Refineries

Projections of the response of the nation's petroleum refineries to a tax on sulfur emissions have been made on a plant-by-plant basis, using the emissions and control data shown in appendix B; these projections are summed to obtain industry totals. However, the resulting projections

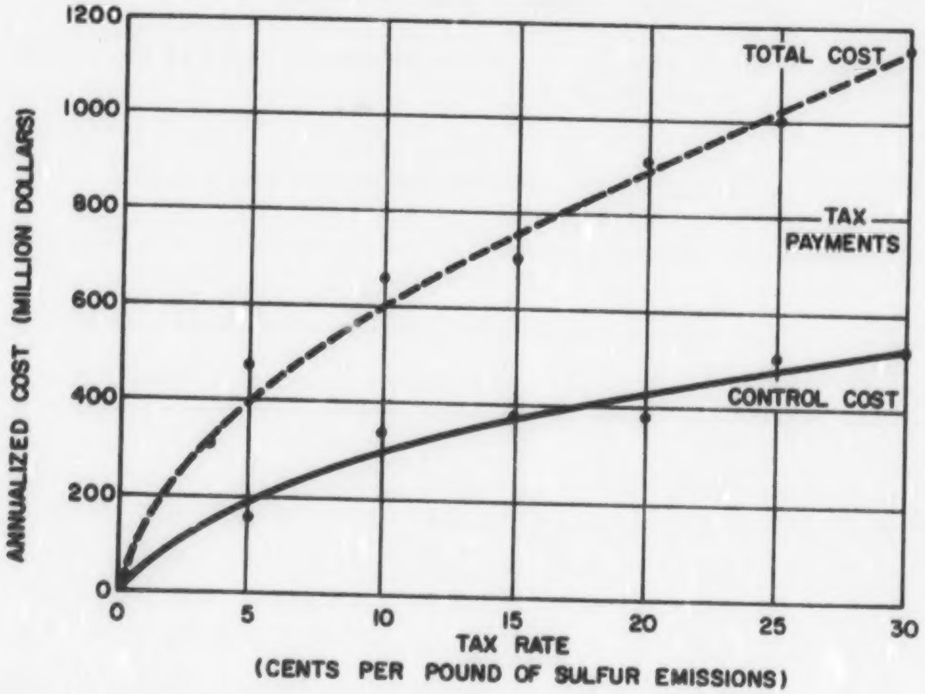

Figure 15. Total cost induced by a tax on sulfur emissions: area sources--1978 (Source: Research Triangle Institute).

are approximations that do not reflect all of the variations in process types and operating procedures among refineries. In addition, emissions may be understated, since the available data do not make it possible to account for the disposition of all of the sulfur contained in the crude oil processed.

4.4.1 Background

In 1968, petroleum refineries accounted for an estimated 6.3 percent of the estimated nationwide sulfur emissions from all sources.* Petroleum products are widely used in other industries, especially as fuel for the generation of electricity, as feedstock for the petrochemical industry, and as the basic material for asphalt roofing and paving. Therefore, their supply and price behavior are important to the economy beyond the influence of their better known, direct uses as vehicle fuels and heating oils.

There were 263 petroleum refineries in the United States in 1970. The bulk of refining capacity is concentrated in 30 to 35 firms. Of these, 16 are fully integrated international corporations making up the so-called large majors of the industry; another 8 firms may be classified as small majors and are also fully integrated. The remainder of the firms in the industry are somewhat smaller; they either are not fully integrated or operate in a limited market. In 1970, petroleum refining capacity was about 12.154 million barrels daily,† and annual production, as measured by actual runs-to-stills, was 3,967.5 million barrels (see fig. 16).

4.4.2 Industry Growth

From 1950 through 1970, petroleum refining (measured by runs-to-stills) increased an average of 3.2 percent annually. However, as shown in figure 16, growth has varied throughout the period. For the period 1970-78, the annual growth rate assumed for petroleum refining is 4 percent.‡ This implies domestic refining of approximately 5,268.8 million barrels in 1978.

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*National Air Pollution Control Administration, Nationwide Inventory of Air Pollutant Emissions--1968, Raleigh, N. C., August 1970.

†Petroleum Refinery Listing, Research Triangle Institute.

‡Research Triangle Institute, Unpublished Data for the Cost of Clean Air, 1973.

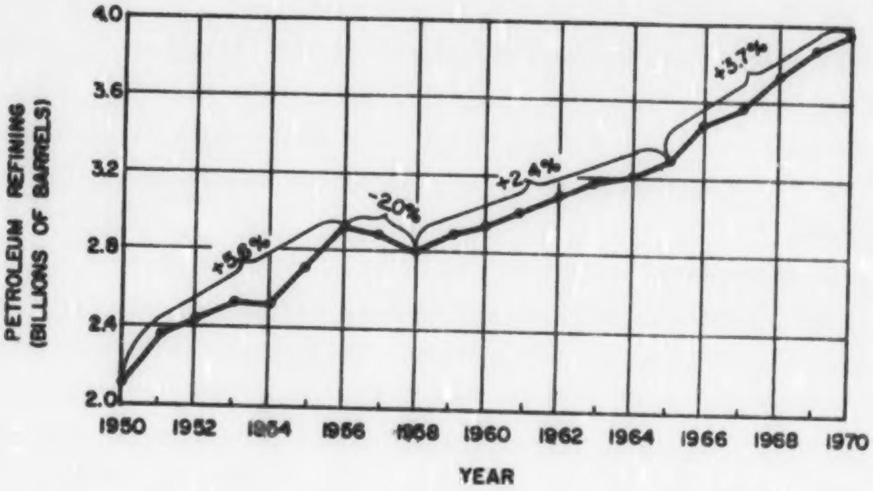

Figure 16. Petroleum refining trends (Source: Research Triangle Institute).

4.4.3 Effectiveness

The response of the nation's petroleum refining industry to a tax on their emissions of sulfur has been projected for several tax rates ranging from 0 to 30 cents per pound of sulfur. Since all of the emissions control alternatives available to refineries and costed for this study result in the recovery of sulfur, it is necessary to credit revenues from its sale. However, because of the uncertainties surrounding the future price of recovered sulfur, the impact of the assumed market price of recovered sulfur on the decisions by refineries to control emissions is analyzed separately in section 4.4.5. In this section, a sulfur price of $10 per ton was used as the most likely 1978 market value for recovered sulfur from petroleum refineries (see appendix E for an extended discussion of this choice).

Sulfur emissions from all petroleum refineries, assuming no additional controls other than those required by New Source Performance Standards (a zero tax), are projected to be about 772,000 tons in 1978 (see table 19). These projected emissions are fairly equally distributed across the three major process sources (Claus plants, catalytic crackers, and fuel oil combustion).

Tabular results of the projected response of all petroleum refineries to the sulfur tax for several tax rates are provided in table 20. This

Table 19. Projected sulfur emissions from petroleum refineries--1978*

Source	Annual sulfur emissions (thousand tons of sulfur)
Claus plants	280
Fluid catalytic crackers	256
Fuel combustion processes	221
Thermofor and Houdriflow catalytic cracker	15
Total	772

*Assuming only controls required by New Source Performance Standards.

Source: Research Triangle Institute.

information, plus the effect of several additional tax rates, is graphically presented in figure 17. Throughout the range of taxes being considered, the only economically feasible control option was the extended treatment of the hydrogen sulfide gas stream via Claus plants or via additions to present Claus plants. No control is induced for emissions from refinery combustion processes or from catalytic crackers because of the high costs of the control alternatives. A large refinery, for example, would find it uneconomical to control emissions from combustion processes until a tax of about 33 cents is introduced. Catalytic cracker emissions would not be controlled until a tax of about $1.60 is introduced. As a result, only 36 percent of the projected emissions would be controlled even with a 30-cent tax. However, the tax payments on emissions from these two sources might encourage the development of other, more cost-effective control techniques than those currently available.

At a tax rate as low as 1 cent, the average large refinery without a Claus plant would find it more economical to install such a plant rather than to pay the maximum amount of tax. At a 2- or 3-cent tax rate, large refineries with two-stage Claus plants are projected to upgrade their plants to four-stage units.

Reductions in emissions are induced by increasing the tax rate to about 20 cents per pound. Tax rates between 20 and 30 cents per pound, however, are projected to induce only small additional reductions in emissions.

Table 20. Projected response of all petroleum refineries to a national tax on sulfur emissions--1978 (recovered sulfur valued at $10 per ton)

Emissions source	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control cost (thousands)	Annual tax payment (thousands)
		Tax rate:	5 cents per pound of sulfur emissions		
Catalyst regenerators	270.6	0.0	$ 27,061	$ 0	$ 27,061
Fluid catalytic crackers	255.5	0.0	25,554	0	25,554
Thermofor and Houdriflow catalytic crackers	15.1	0.0	1,507	0	1,507
Claus plants	116.6	163.7	17,254	5,596	11,659
Fuel combustion	220.9	0.0	22,088	0	22,088
Total from all sources	608.1	163.7	$ 66,403	$5,596	$ 60,808
		Tax rate:	10 cents per pound of sulfur emissions		
Catalyst regenerators	270.5	0.0	$ 54,123	$ 0	$ 54,123
Fluid catalytic crackers	255.5	0.0	51,108	0	51,108
Thermofor and Houdriflow catalytic crackers	15.0	0.0	3,015	0	3,015
Claus plants	46.2	234.0	23,977	14,730	9,247
Fuel combustion	220.8	0.0	44,176	0	44,176
Total from all sources	537.5	234.0	$122,276	$14,730	$107,546
		Tax rate:	15 cents per pound of sulfur emissions		
Catalyst regenerators	270.5	0.0	$ 81,183	$ 0	$ 81,183
Fluid catalytic crackers	255.5	0.0	76,661	0	76,661
Thermofor and Houdriflow catalytic crackers	15.0	0.0	4,522	0	4,522
Claus plants	18.3	261.9	27,184	21,670	5,514
Fuel combustion	220.8	0.0	66,264	0	66,264
Total from all sources	509.6	261.9	$174,631	$21,670	$152,961
		Tax rate:	20 cents per pound of sulfur emissions		
Catalyst regenerators	270.5	0.0	$108,244	$ 0	$108,244
Fluid catalytic crackers	255.5	0.0	102,214	0	102,214
Thermofor and Houdriflow catalytic crackers	15.0	0.0	6,030	0	6,030
Claus plants	8.3	271.9	28,413	25,056	3,357
Fuel combustion	220.8	0.0	88,351	0	88,351
Total from all sources	499.6	271.9	$225,008	$25,056	$199,952
		Tax rate:	25 cents per pound of sulfur emissions		
Catalyst regenerators	270.5	0.0	$135,304	$ 0	$135,304
Fluid catalytic crackers	255.5	0.0	127,768	0	127,768
Thermofor and Houdriflow catalytic crackers	15.0	0.0	7,536	0	7,536
Claus plants	5.9	274.4	29,114	26,161	2,954
Fuel combustion	220.8	0.0	110,438	0	110,438
Total from all sources	497.2	274.4	$274,856	$26,161	$248,696
		Tax rate:	30 cents per pound of sulfur emissions		
Catalyst regenerators	270.6	0.0	$162,366	0	$162,366
Fluid catalytic crackers	255.5	0.0	153,322	0	153,322
Thermofor and Houdriflow catalytic crackers	15.1	0.0	9,044	$ 0	9,044
Claus plants	4.9	275.3	29,640	26,681	2,959
Fuel combustion	220.9	0.0	132,525	0	132,525
Total from all sources	496.4	275.3	$324,519	$26,681	$297,837

Source: Research Triangle Institute.

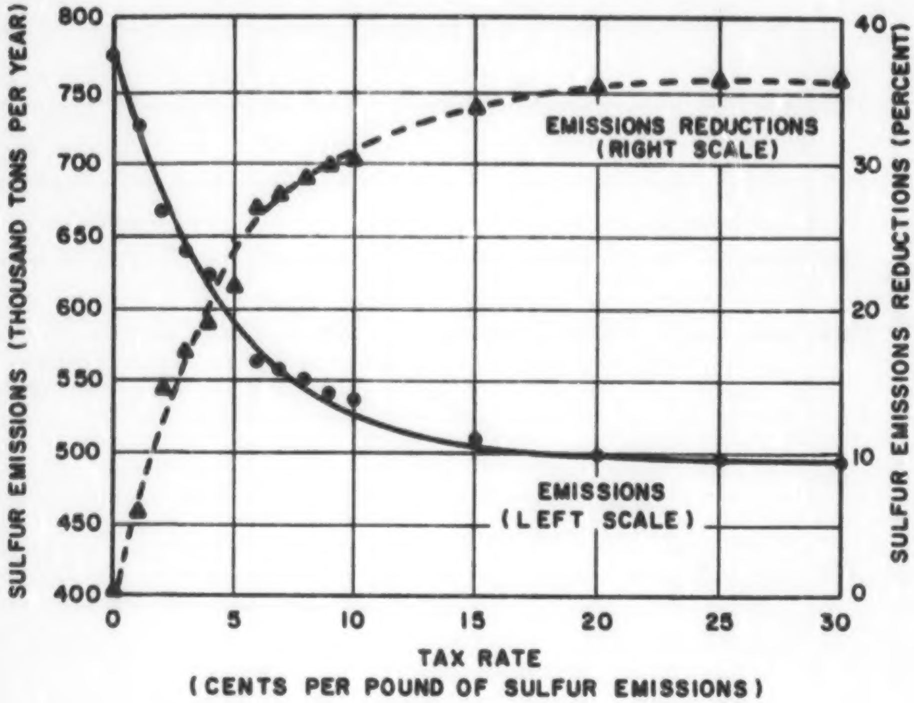

Figure 17. Effectiveness of a tax on sulfur emissions: petroleum refining--1978 (Source: Research Triangle Institute).

4.4.4 Costs

The total cost to the petroleum refining industry is shown in table 20 for selected tax rates. As shown in figure 18, they increase almost linearly for all tax rates between 0 and 30 cents because the majority of the emissions (74 percent) would not be controlled over that range. Since tax rates up to 30 cents are not projected to induce substantial reductions in sulfur emissions, the major cost element over the entire range of taxes would be the tax payments. A remaining defense for the tax, however, is that the continuing tax liability would, very likely, induce the development of more cost-effective alternatives for controlling emissions from catalyst regenerators and fuel combustion than those currently available.

The relative magnitude of these costs on a per-unit-of-product basis assuming a perfectly inelastic demand for petroleum products and not including the effects of the corporate income tax is shown in figure 19. For reference, the 1970 average value at the refinery of all refined petroleum products, exclusive of excise taxes, was about $5.25 per barrel.

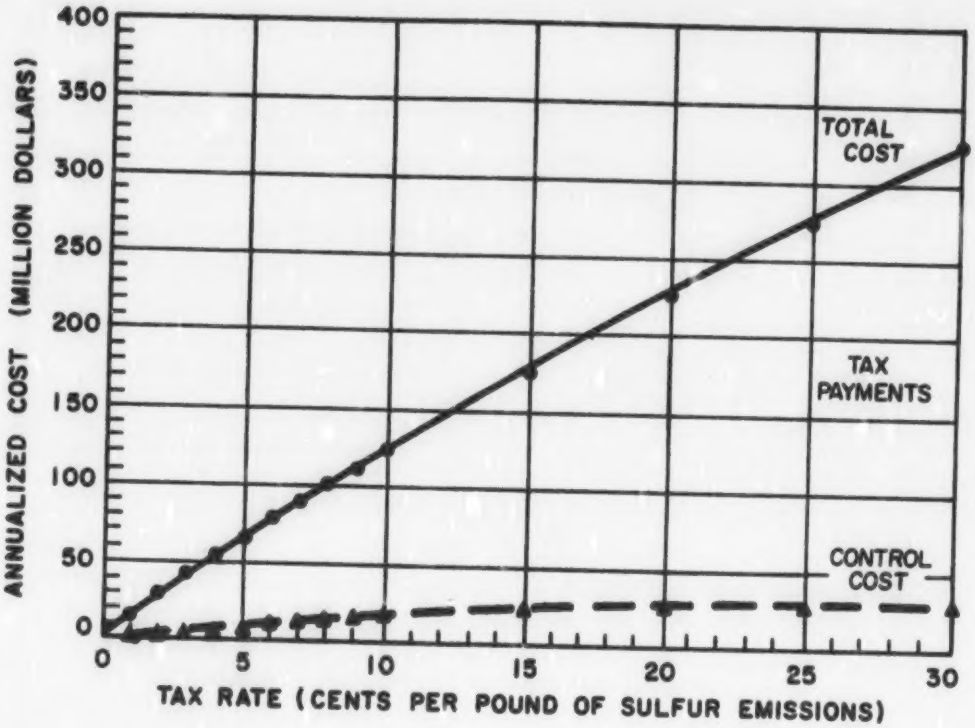

Figure 18. Total costs induced by a tax on sulfur emissions: petroleum refining--1978 (Source: Research Triangle Institute).

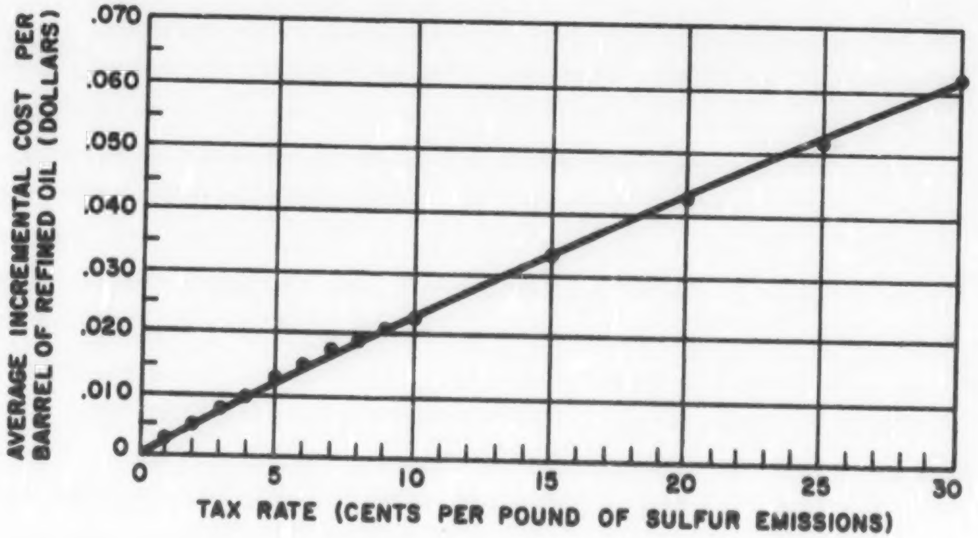

Figure 19. Average total* incremental costs per barrel of refined oil induced by a tax on sulfur emissions: petroleum refining--1978 (*control cost plus tax payments) (Source: Research Triangle Institute).

At a tax rate as high as 30 cents, the sum of control cost and tax payments distributed equally across all refined oil would represent only about one percent of that value.

4.4.5 Sensitivity Analysis

The projected effectiveness and costs of a tax on the sulfur emissions of petroleum refineries is influenced not only by the tax rate, but also by the assumed market value of the recovered sulfur and the estimated control costs of the sulfur emissions control alternatives. To examine the sensitivity of the projected effectiveness and costs of the sulfur tax, a sensitivity analysis was performed. Parametric variations were introduced in the assumed future value for recovered sulfur and in the cost estimates presented in appendix B. The resulting percentage deviations in both emissions and total costs from those which obtain in the presence of the assumed sulfur price of $10 and of control costs as presented in appendix B are given for variations in the price of sulfur in figure 20 and for variations in control costs in table 20. The base values refer to

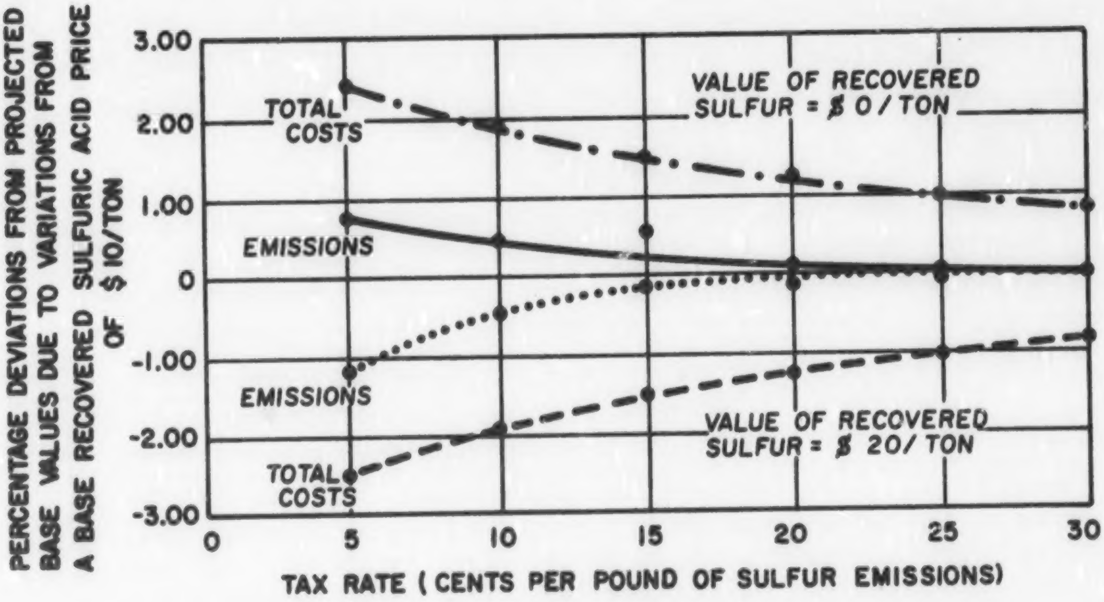

Figure 20. Sensitivity of the effectiveness and total costs of a tax on sulfur emissions to the value of recovered sulfur: petroleum refining--1978 (The base values refer to both the total control costs and the emission levels that obtain when the base sulfur prices is assumed equal to $10 per ton) (Source: Research Triangle Institute).

both the total control costs and the emission levels that obtain when the base sulfur price is assumed equal to $10 per ton.

As is shown in figure 20, reducing or increasing the market value of recovered sulfur by $10 per ton has greater influence at low tax rates. However, the magnitude of those responses is small, never exceeding 2.5 percent. For example, if the value of recovered sulfur were $0 per ton instead of $10 as used in the analysis above, for a tax rate of 10 cents, emissions would be about 0.5 percent and total costs about 2.0 percent higher than projected above. Sulfur emissions and total cost projections under alternative market values of sulfur appear to level off very rapidly as the tax rate is increased, reflecting the decreasing importance of the price of recovered sulfur in influencing the behavior of refineries. The general conclusion of this analysis, then, is that substantial variation in the market price of recovered sulfur is not likely to affect significantly the overall predicted effects of a tax on sulfur emissions from petroleum refineries as discussed in previous sections.

The sensitivity of the emissions and total cost projections to positive and negative percentage deviations in the control cost estimates are presented in table 21. In general, the projected effectiveness and costs are not significantly influenced by these percentage changes in control costs. However, there is a significant exception. Control costs estimates

Table 21. Sensitivity of the effectiveness and total cost of a tax on sulfur emissions to the control cost estimates: petroleum refineries--1978

Change in all control cost estimates (percent)	Change in emissions (percent)						Change in total costs (percent)					
	Tax rate (cents per pound of sulfur emissions)						Tax rate (cents per pound of sulfur emissions)					
	5	10	15	20	25	30	5	10	15	20	25	30
+20	2.5	1.8	2.5	1.1	0.4	0.2	2.0	2.6	2.5	2.4	2.1	1.8
+10	0.8	0.9	1.7	0.4	0.2	0.0	1.1	1.4	1.3	1.2	1.0	0.9
+ 5	0.2	0.5	0.9	0.1	0.1	0.0	0.5	0.7	0.7	0.6	0.5	0.5
- 5	-0.3	-0.5	-0.4	-0.2	-0.1	- 0.8	-0.6	-0.7	-0.7	-0.6	-0.5	-0.5
-10	-1.2	-0.9	-0.9	-0.3	-0.2	-18.1	-1.2	-1.4	-1.4	-1.3	-1.1	-1.2
-20	-8.0	-2.9	-1.7	-0.5	-0.3	-27.2	-2.9	-3.1	-3.0	-2.5	-2.1	-4.5

Source: Research Triangle Institute.

that are 20 percent lower than those developed for this study would induce petroleum refineries to reduce substantially the sulfur emissions from fuel combustion. With a tax of 30 cents per pound and control costs for desulfurization that are 20 percent lower than those projected in appendix B, emissions from fuel combustion would be reduced by 61 percent or by 134,000 tons from a currently projected level of 221,000 tons from those sources. Overall, emissions would be 27 percent less than those projected without the application of control policies.

4.5 Sulfuric Acid Producers

Projections of the response of the nation's sulfuric acid producers to a tax on sulfur emissions have been made on a plant-by-plant basis using the emissions and control data shown in appendix C; these projections are summed to obtain industry totals. The resulting cost and emission estimates are approximations in that they do not fully reflect variations in process types and operating procedures among sulfuric acid producers due to the discrete nature of this analysis. However, the results are regarded as very reasonable first order estimates.

4.5.1 Background

In 1968, sulfuric acid production accounted for an estimated 1.8 percent of the estimated nationwide sulfur emissions from all sources.* Sulfuric acid is a strong, low priced, inorganic acid utilized in the production of phosphate fertilizers and other industrial chemicals, in the processing of petroleum, in the production of synthetic fabrics, in the pickling of steel, and in many other metallurgical applications.

Most of the nation's approximately 240 sulfuric acid plants are owned by large, diversified corporations. These plants sometimes sell the acid commercially but, more often, the plants provide one link in a vertically integrated company whose final product requires sulfuric acid as an intermediate input. These companies include sulfur and chemical producers, petroleum refineries, fertilizer plants, and smelters.

Over 97 percent of all sulfuric acid is produced by the contact process.† The remainder is produced by the obsolescent lead chamber process, currently being phased out. This analysis is limited to a study of the effects of a tax on sulfur emissions from the 183 plants using the contact process; it does not include sulfuric acid production at primary nonferrous smelters or petroleum refineries. Those sources are treated elsewhere in this study.

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*National Air Pollution Control Administration, Nationwide Inventory of Air Pollutant Emissions--1968, Raleigh, N. C., August 1970.

†Engineering Analysis of Emissions Control Technology for Sulfuric Acid Manufacturing Process, Final Report, Chemical Construction Corporation, New York, N. Y., For National Air Pollution Control Administration, March 1970.

In 1970, sulfuric acid capacity was about 94,322 tons daily, and production for the year was 29,525 million tons (see fig. 21).

4.5.2 Industry Growth

From 1950 through 1970, sulfuric acid production increased by an average of 4.2 percent annually. However, as shown in figure 21, growth has varied throughout the period.

Expected growth in sulfuric acid capacity allows for two new 1,500-ton-per-day plants each year between 1970 and 1978.* Assuming that the same capacity-to-output relationship exists in 1978 as existed in 1970, 1978 production would be 37.035 million tons. The 1970-78 growth rate, then, is assumed to be 2.9 percent.

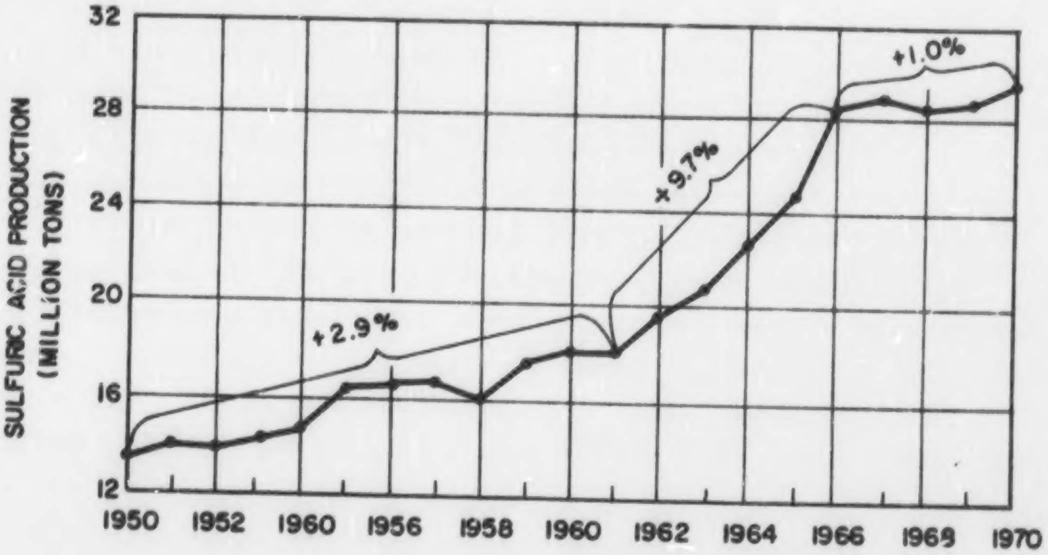

Figure 21. Sulfuric acid production trends (Source: U.S. Department of Commerce).

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*Research Triangle Institute, Unpublished Data for the Cost of Clean Air, 1973.

4.5.3 Effectiveness

The reponse of the nation's sulfuric acid industry to a tax on their emissions of sulfur was projected for selected tax rates. Since all of the emissions control alternatives available to this industry and costed for this study result in the recovery or increased production of sulfuric acid, it is reasonable to allow credit for revenues from its sale. Within this section we have used $10 per ton as being the most likely 1978 market value for additional sulfuric acid production from sulfuric acid producers due to the tax. However, because of the uncertainties surrounding the future price of recovered sulfuric acid (see app. E), the impact of the assumed market price of recovered sulfur on the decisions by sulfuric acid producers to control emissions is analyzed separately below (see sec. 4.5.5).

Sulfur emissions from all sulfuric acid producers, assuming no additional control other than those required by New Source Performance Standards (a zero tax), are projected to be about 377,000 tons in 1978 (see table 22).

Tabular results of the projected response of all sulfuric acid producers for several tax rates are provided in table 23. This information is graphically presented in figure 22. Control of sulfur emissions would not be induced below a 5-cent tax rate.

Increasing the tax rate by 10 cents per pound (from 5 to 15 cents) is expected to effect an 84-percent reduction in emissions from the level (385 thousand tons) that would occur at a 5-cent tax rate. Further doubling of the tax rate from 15 to 30 cents per pound of sulfur emitted will yield only a further 22-percent reduction from emissions at the 15-cent tax rate. At a tax rate of 20 cents, 87 percent of potential emissions are expected to be controlled. Beyond that rate, virtually no further reductions are induced.

Table 22. Projected emissions from sulfuric acid production--1978

Source	Annual sulfur emissions (thousand tons of sulfur)
Normal plants, mist	10
Oleum plants, mist	12
All plants, gaseous	354
Total	376

*Assuming only controls required by New Source Performance Standards.

Source: Research Triangle Institute.

Table 23. Projected response of all sulfuric acid plants to a national tax on sulfur emissions--1978 (recovered sulfuric acid valued at $10 per ton)

Emissions source	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control cost (thousands)	Annual tax payment (thousands)
Tax rate: 5 cents per pound of sulfur emissions					
Gaseous	362.6	0.0	$36,257	$0	$36,257
Mist	22.8	0.0	2,289	0	2,289
Normal	10.7	0.0	1,076	0	1,076
Oleum	12.1	0.0	1,213	0	1,213
Total from all sources	385.4	0.0	$38,546	$0	$38,546
Tax rate: 10 cents per pound of sulfur emissions					
Gaseous	82.9	279.7	$55,498	$38,927	$16,570
Mist	13.8	9.1	3,912	1,147	2,765
Normal	10.7	0.0	2,152	0	2,152
Oleum	3.1	9.1	1,760	1,147	613
Total from all sources	96.7	288.8	$59,410	$40,074	$19,335
Tax rate: 15 cents per pound of sulfur emissions					
Gaseous	47.4	315.1	$61,505	$47,269	$14,236
Mist	13.5	9.3	5,292	1,217	4,075
Normal	10.5	0.2	3,228	65	3,163
Oleum	3.0	9.1	2,064	1,152	912
Total from all sources	60.9	324.4	$66,797	$48,486	$18,311
Tax rate: 20 cents per pound of sulfur emissions					
Gaseous	44.4	318.1	$66,044	$48,270	$17,773
Mist	4.3	13.6	5,974	4,255	1,719
Normal	1.9	8.9	3,613	2,871	742
Oleum	2.4	9.7	2,361	1,384	977
Total from all sources	48.7	336.7	$72,018	$52,525	$19,492
Tax rate: 25 cents per pound of sulfur emissions					
Gaseous	44.0	318.5	$70,461	$48,447	$22,014
Mist	3.4	19.4	6,371	4,663	1,708
Normal	1.5	9.2	3,781	3,021	761
Oleum	1.9	10.2	2,589	1,642	947
Total from all sources	47.4	337.9	$76,831	$53,110	$23,722
Tax rate: 30 cents per pound of sulfur emissions					
Gaseous	43.9	318.6	$74,854	$48,499	$26,356
Mist	3.0	19.9	6,694	4,893	1,801
Normal	1.4	9.3	3,929	3,071	858
Oleum	1.6	10.6	2,765	1,321	949
Total from all sources	46.9	338.5	$81,548	$53,392	$28,158

Source: Research Triangle Institute.

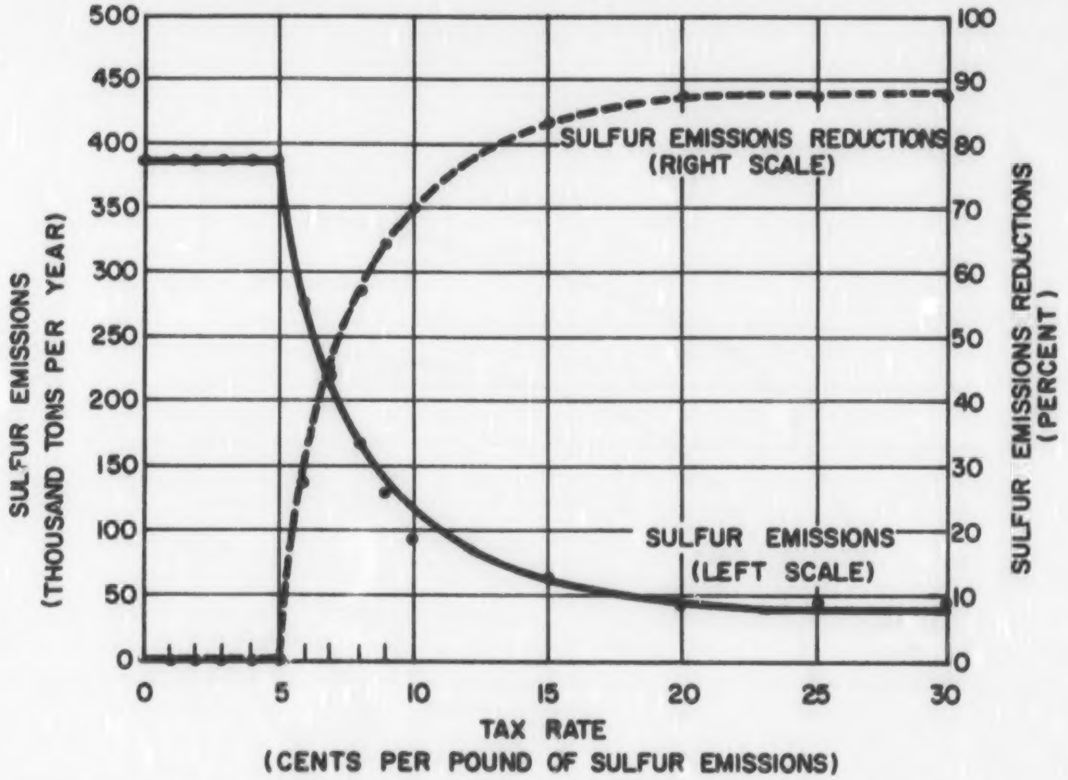

Figure 22. Effectiveness of a tax on sulfur emissions: sulfuric acid producers--1978 (Source: Research Triangle Institute).

4.5.4 Costs

The total annualized cost to the sulfuric acid producers are shown in table 23 for selected tax rates. Those same results are given graphically in figure 23; costs increase at a decreasing rate because relatively small increases in control costs yield significant emission reductions over the 15- to 30-cent tax range. For example, a 10-percent increase in control costs (from $48 to $53 million) causes a 23-percent reduction in emissions.

Some insight of the relative magnitude of these costs (control cost plus tax payments) is shown by allocating them on a per-unit-of-product basis as shown in figure 24. For reference, the 1970 average value of sulfuric acid was about $20 per ton. At a tax rate as high as 30 cents, these costs would represent about 10 percent of that value.

4.5.5 Sensitivity Analysis

The projected effectiveness and costs of a tax on the sulfur emissions of sulfuric acid producers is influenced not only by the tax rate but also

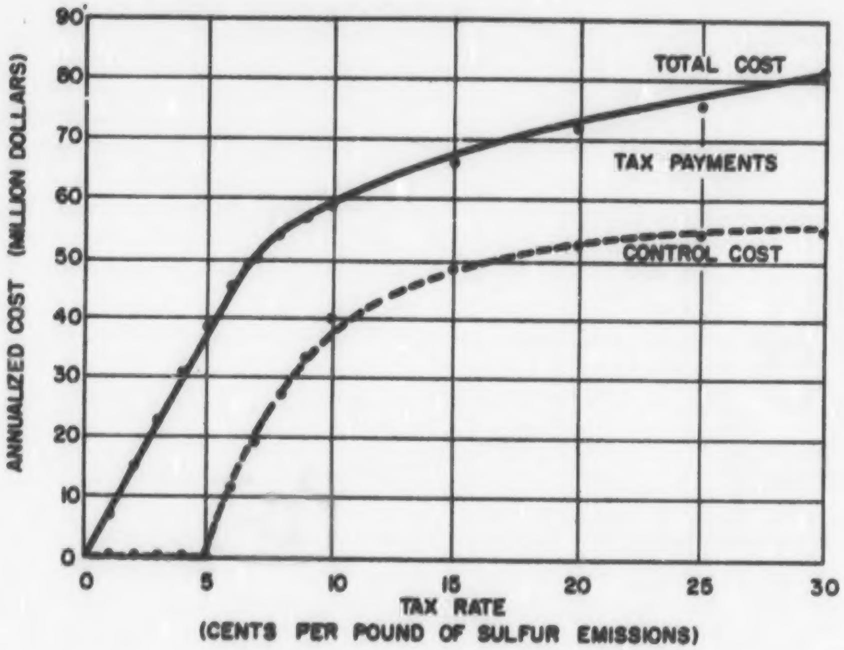

Figure 23. Total costs induced by a tax on sulfur emissions: sulfuric acid producers--1978 (Source: Research Triangle Institute).

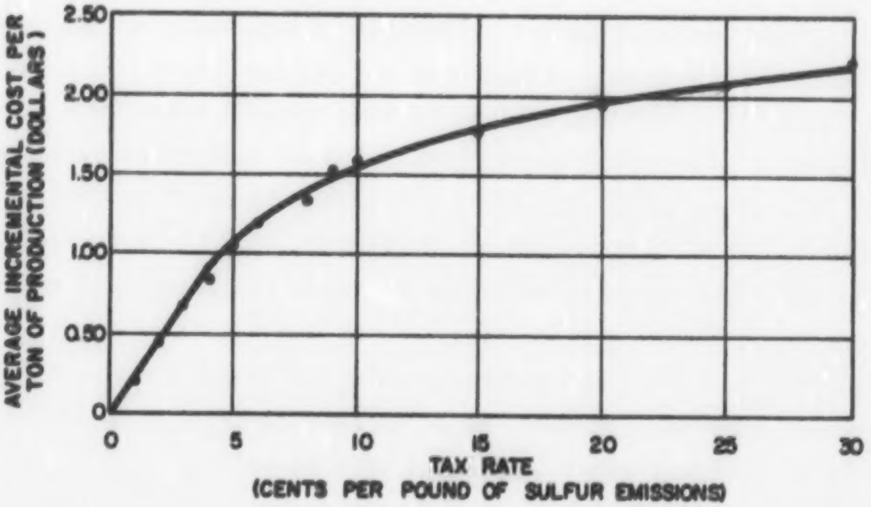

Figure 24. Average total* incremental costs per ton of acid production induced by a tax on sulfur emissions: sulfuric acid producers--1978 (*control cost plus tax payments) (Source: Research Triangle Institute).

by the assumed market value of the recovered sulfuric acid and the estimated control costs of the sulfur emissions control alternatives. To examine the sensitivity of the projected effectiveness and costs of the sulfur tax, a sensitivity analysis was performed. Parametric variations were introduced in the assumed future value for recovered sulfur and in the control cost estimates presented in appendix C. The resulting percentage deviations in emissions and total costs from those which obtain in the presence of the assumed sulfur price of $10 and of control costs as presented in appendix C are given for variations in the price of sulfur in figure 25 and for variations in control costs in table 24.

As shown in figure 25, reducing or increasing the market value of the recovered sulfuric acid by $10 per ton changes projected total costs by about 5 percent in the direction opposite the price change for all tax rates that induce emissions control. For example, if a value of $0 per ton for recovered sulfur is used instead of $10, then for a tax rate of 10 cents,

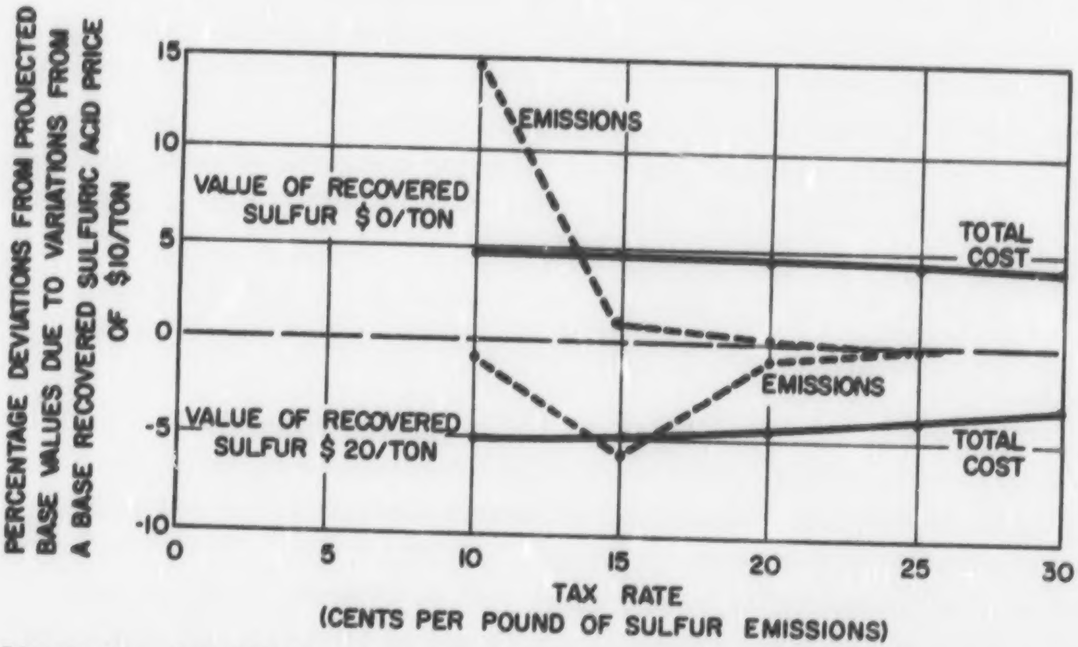

Figure 25. Sensitivity of the effectiveness and total costs of a tax on sulfur emissions to the value of recovered sulfur: sulfuric acid producers--1978 (*The base values refer to both the total control costs and the emission levels that obtain when the base sulfur price is assumed equal to $10 per ton) (Source: Research Triangle Institute).

Table 24. Sensitivity of effectiveness and total costs of tax on sulfur emissions to the control cost estimates: sulfuric acid producers--1978

Change in all control cost estimates (percent)	Change in emissions (percent)						Change in total cost (percent)					
	Tax rate (cents per pound of sulfur emissions)						Tax rate (cents per pound of sulfur emissions)					
	5	10	15	20	25	30	5	10	15	20	25	30
+20	0.0	66.1	14.3	6.4	2.3	1.1	0.0	12.5	15.1	15.4	14.6	13.9
+10	0.0	21.2	8.1	2.7	1.3	0.6	0.0	6.7	7.6	7.7	7.3	7.0
+ 5	0.0	14.7	0.4	2.1	0.5	0.4	0.0	3.4	3.9	3.9	3.7	3.5
- 5	0.0	-10.5	- 5.9	-0.4	-0.4	-0.8	0.0	- 3.6	- 3.9	- 3.9	- 3.7	- 3.5
-10	-23.6	-10.6	-15.6	-0.9	-0.6	-1.6	-0.3	- 7.4	- 8.0	- 7.8	- 7.4	-14.0
-20	-31.6	-27.8	-18.0	-2.6	-1.3	-1.0	-3.6	-15.5	-16.2	-15.6	-14.7	- 7.0

Source: Research Triangle Institute.

emissions are 15 percent and total cost 5 percent higher than projected above. These deviations in the price of sulfur would not substantively affect the rate of emissions for any tax rate at or above 20 cents. The largest percentage reduction in emissions, compared to those that occur when the price of sulfur is $10 per ton, occurs at a tax rate of 15 cents when the sulfur price is $20 per ton; that percentage deviation is slightly more than 5 percent. All other such percentage reductions are smaller. On the other hand, when the recovered sulfur is assumed worthless, emissions could increase as much as 15 percent above those levels projected when the value of sulfur is $10 per ton; this most sizable deviation occurs at a tax rate of 10 cents per pound. At tax rates below 10 cents per pound, no emissions reductions are stimulated for any of the chosen variations in sulfur prices.

The sensitivity of the emissions and total cost projections to positive and negative percentage deviations in the control costs estimates are presented in table 24. Reductions in control costs of 10 percent would induce control at 5 cents per pound by some sulfuric acid plants. Emissions are most influenced in the midtax ranges (10 to 15 cents), whereas total costs are most affected by changes of ± 10 and 20 percent in control costs across all tax rates.

4.6 Primary Nonferrous Smelters

Projections of the response of the nation's primary copper, zinc, and lead smelters to a tax on sulfur emissions have been made on a smelter-by-smelter basis using the emissions and control data shown in appendix D. Individual projections were summed to obtain predictions for the entire industry. The resulting projections, however, are approximations that do not reflect all of the variations in process types and operating procedures among smelters.

4.6.1 Background

Copper, zinc, and lead smelters accounted for an estimated 11.7 percent of the estimated 1968 nationwide sulfur emissions from all sources.* The metals produced from these smelting operations are used in a myriad of applications: for galvanizing, for castings, in electrical equipment and supplies, in brass and bronze products, in storage batteries, and as additives to gasoline. In 1970, primary smelter production capacities in copper (15 plants), zinc (7 plants), and lead (6 plants) were 4,662, 2,236, and 2,114 tons per day, respectively. Actual production figures for 1970, in thousands of tons, were 1,765 (copper), 881 (zinc), and 572 (lead) (see fig. 26).

4.6.2 Industry Growth

From 1950 through 1970, copper production grew fairly steadily (1.8 percent annually) whereas the production growth rates in primary zinc and lead production were both more erratic and lower overall. Copper production is expected to grow 2.2 percent annually reaching 2.101 million tons annually by 1978. Both zinc and lead production were projected to remain at their 1970 levels through 1978, since only negligible growth is anticipated.†

4.6.3 Effectiveness

The response of the nation's primary nonferrous smelters to a tax on their emissions of sulfur were projected for several tax rates between 0 and 30 cents per pound of sulfur. Since the emissions control alternatives costed for primary nonferrous smelters result in the recovery of sulfur, it is necessary to allow credit for revenues from its sale. Within this section we have used $0 per ton as being the most likely 1978 market value for sulfuric acid recovered by nonferrous smelters. This price reflects

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*National Air Pollution Control Administration, Nationwide Inventory of Air Pollutant Emissions--1968, Raleigh, N. C., August 1970.

†Research Triangle Institute, Unpublished Data for the Cost of Clean Air, 1973.

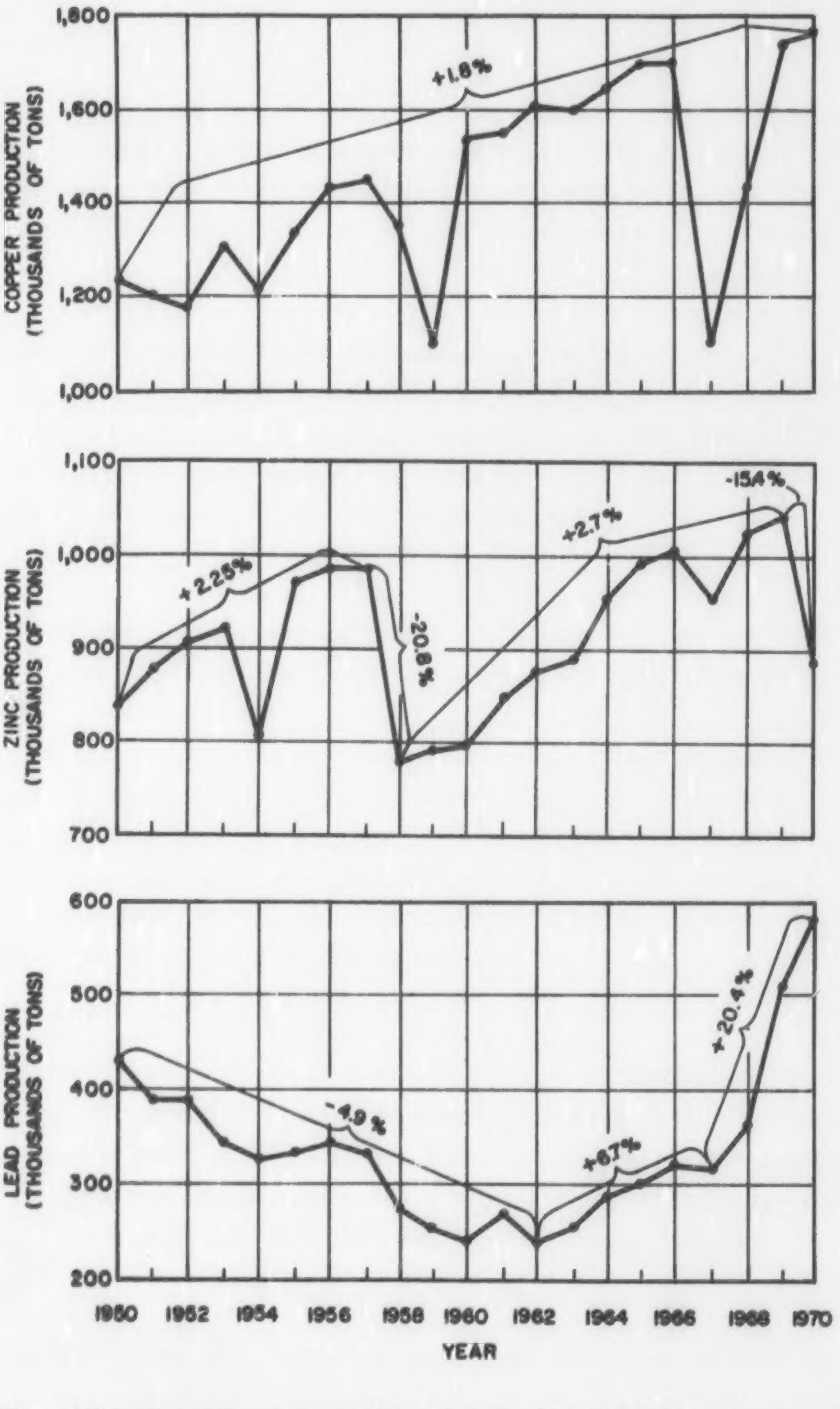

Figure 26. Primary nonferrous smelting trends (*Indicated rates are compounded annual growth rates) (Source: Research Triangle Institute).

the fact that most of the nation's smelters are not located in areas where their recovered acid can be easily sold. However, because of the uncertainties surrounding the future price of recovered sulfuric acid (see app. E), the impact of the assumed market price of recovered sulfuric acid on the decisions by smelters to control emissions is analyzed separately (see sec. 4.6.5).

Sulfur emissions from all nonferrous smelters are projected to be about 1.7 million tons in 1978, assuming a zero tax and no further control inducements (see table 25).

Over 90 percent of all projected sulfur emissions from smelters are from copper smelters, primarily copper smelters without an acid plant. This percentage is greater than copper's share of the total production (measured in tons) of primary nonferrous smelters due to differences in the sulfur content of the three ores and in processing techniques.

Tabular results of the projected response of all primary nonferrous smelters to the sulfur tax for several tax rates are provided in table 26. This information is presented graphically in figure 27.

Tax rates below 5 cents per pound are projected to induce primary nonferrous smelters to reduce substantially their sulfur emissions as compared to those at the zero tax level. For example, the projections indicate that a tax of 2 cents would cause most copper smelters to reduce sulfur emissions to 69 percent of their zero tax level emissions. This would be a reduction of 55 percent in sulfur emissions from all nonferrous smelters taken together. A tax of 3 cents would induce additional control by copper smelters, cause zinc smelters without an acid plant to control,

Table 25. Projected sulfur emissions from primary nonferrous smelters--1978

Source	Annual sulfur emissions (thousand tons of sulfur)
Copper smelters	1,534
Zinc smelters	56
Lead smelters	60
Total	1,650

*Assuming no implementation of emissions standards.

Source: Research Triangle Institute.

Table 26. Projected response of all primary nonferrous smelters to a national tax on sulfur emissions--1978 (recovered sulfur valued at $0 per ton)

Emissions source*	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control cost (thousands)	Annual tax payment (thousands)
	Tax rate:	5 cents per pound of sulfur emissions			
Copper total	248.2	1,286.2	78,070	53,253	24,816
Cu-A	33.5	720.7	32,021	28,674	3,348
Cu-B	30.3	177.3	15,644	12,617	3,027
Cu-C	32.2	118.8	6,372	3,153	3,218
Cu-D	152.2	269.4	24,033	8,809	15,224
Zinc total	7.8	47.9	2,563	1,770	793
Zn-A	1.8	43.4	1,550	1,368	182
Zn-B	2.3	4.5	637	402	235
Zn-C	3.7	0.0	376	0	376
Lead total	22.6	37.2	4,465	2,183	2,282
Pb-A	0.6	11.7	947	884	64
Pb-B	1.3	25.5	1,438	1,299	138
Pb-C	20.7	0.0	2,080	0	2,080
Total all sources	278.6	1,371.3	85,098	57,206	27,892
	Tax rate:	10 cents per pound of sulfur emissions			
Copper total	84.2	1,450.5	88,558	71,770	16,789
Cu-A	33.5	720.7	35,369	28,674	6,695
Cu-B	30.5	177.3	18,670	12,617	6,053
Cu-C	2.8	148.2	7,082	6,522	560
Cu-D	17.4	404.3	27,437	23,957	3,481
Zinc total	3.6	52.0	3,040	2,282	758
Zn-A	1.8	43.4	1,732	1,368	364
Zn-B	1.5	5.3	830	511	319
Zn-C	0.3	3.3	478	403	75
Lead total	22.6	37.2	6,746	2,183	4,563
Pb-A	0.6	11.7	1,011	884	128
Pb-B	1.3	25.5	1,576	1,299	276
Pb-C	20.7	0.0	4,159	0	4,159
Total all sources	110.4	1,539.7	98,344	76,235	22,110

See footnotes last page.

Table 26. Projected response of all primary nonferrous smelters to a national tax on sulfur emissions--1978 (recovered sulfur valued at $0 per ton) (con.)

Emissions source*	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control cost (thousands)	Annual tax payment (thousands)
	Tax rate: 15 cents per pound of sulfur emissions				
Copper total	84.0	1,450.4	96,953	71,769	25,184
Cu-A	33.5	720.7	38,717	28,674	10,043
Cu-B	30.3	177.3	21,697	12,617	9,080
Cu-C	2.8	148.2	7,362	6,522	841
Cu-D	17.4	404.3	29,177	23,957	5,221
Zinc total	3.6	52.0	3,420	2,281	1,138
Zn-A	1.8	43.4	1,915	1,368	546
Zn-B	1.5	5.3	989	511	477
Zn-C	0.3	3.3	516	403	113
Lead total	6.9	52.9	8,464	6,335	2,128
Pb-A	0.6	11.7	1,075	883	191
Pb-B	1.3	25.5	1,714	1,299	415
Pb-C	5.0	15.7	5,675	4,153	1,522
Total all sources	94.8	1,555.6	108,837	80,386	28,451
	Tax rate: 20 cents per pound of sulfur emissions				
Copper total	70.5	1,464.0	104,901	76,707	28,194
Cu-A	20.0	734.2	41,617	33,611	8,006
Cu-B	30.3	177.3	24,724	12,617	12,106
Cu-C	2.8	148.2	7,642	6,522	1,121
Cu-D	17.4	404.3	30,918	23,957	6,961
Zinc total	3.6	52.0	3,798	2,282	1,516
Zn-A	1.8	43.4	2,097	1,368	727
Zn-B	1.5	5.3	1,147	511	638
Zn-C	0.3	3.3	554	403	151
Lead total	6.9	52.9	9,173	6,336	2,838
Pb-A	0.6	11.7	1,139	884	255
Pb-B	1.3	25.5	1,852	1,299	553
Pb-C	5.0	15.7	6,182	4,153	2,030
Total all sources	81.0	1,568.9	117,872	85,325	32,548

See footnotes last page.

Table 26. Projected response of all primary nonferrous smelters to a national tax on sulfur emissions--1978 (recovered sulfur valued at $0 per ton) (con.)

Emissions source*	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control cost (thousands)	Annual tax payment (thousands)
	Tax rate: 25 cents per pound of sulfur emissions				
Copper total	68.7	1,465.7	111,832	77,487	34,346
Cu-A	18.2	735.9	43,502	34,391	9,111
Cu-B	30.3	177.3	27,750	12,617	15,133
Cu-C	2.8	148.2	7,922	6,522	1,401
Cu-D	17.4	404.3	32,658	23,957	8,701
Zinc total	3.6	52.0	4,178	2,282	1,897
Zn-A	1.8	43.4	2,279	1,368	911
Zn-B	1.5	5.3	1,308	511	798
Zn-C	0.3	3.3	591	403	188
Lead total	6.9	52.9	9,884	6,335	4,549
Pb-A	0.6	11.7	1,203	883	319
Pb-B	1.3	25.5	1,991	1,299	691
Pb-C	5.0	15.7	6,690	4,153	3,539
Total all sources	79.2	1,570.6	125,894	86,104	40,792
	Tax rate: 30 cents per pound of sulfur emissions				
Copper total	68.7	1,465.7	118,702	77,487	41,216
Cu-A	18.2	735.9	45,324	34,391	10,933
Cu-B	30.3	177.3	30,777	12,617	18,160
Cu-C	2.8	148.2	8,203	6,522	1,681
Cu-D	17.4	404.3	34,398	23,957	10,442
Zinc total	3.3	52.4	4,527	2,466	2,060
Zn-A	1.8	43.4	2,461	1,368	1,093
Zn-B	1.2	5.7	1,437	695	741
Zn-C	0.3	3.3	629	403	226
Lead total	6.9	52.9	10,592	6,335	4,256
Pb-A	0.6	11.7	1,266	883	383
Pb-B	1.3	25.5	2,129	1,299	829
Pb-C	5.0	15.7	7,197	4,153	3,044
Total all sources	78.9	1,571.0	133,821	86,288	47,532

*Abbreviations:

See Appendix D.

Copper
- Cu-A Green feed--no acid plant
- Cu-B Green feed--with acid plant
- Cu-C Conventional feed-no acid plant
- Cu-D Conventional feed-with acid plant

Lead
- Pb-A Downdraft sintering--no acid plant
- Pb-B Updraft sintering--no acid plant
- Pb-C Updraft sintering--with acid plant

Zinc
- Zn-A Combination roaster--sintering, no acid plant
- Zn-B Roaster with sintering--with acid plant
- Zn-C Roaster with electrolytic purification and acid plant

Source: Research Triange Institute.

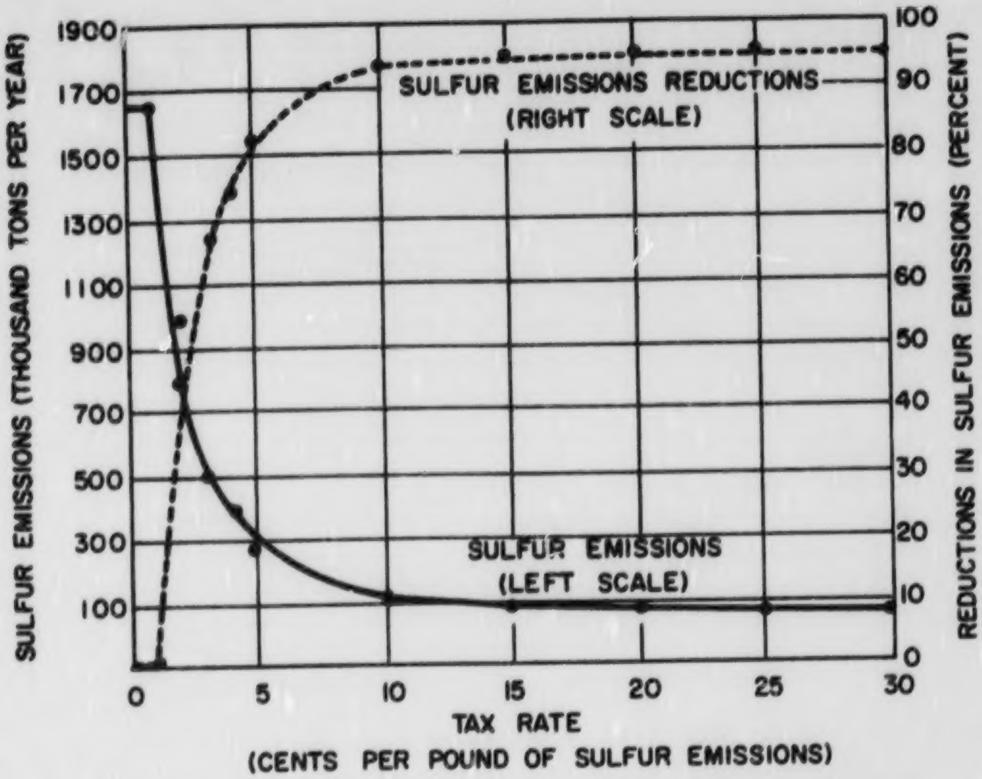

Figure 27. Effectiveness of a tax on sulfur emissions--1978 (Source: Research Triangle Institute).

and some lead smelters would be induced to control. A tax of about 10 cents per pound would cause the last significant reduction in emissions. At this tax, emissions are projected to be only 6 percent of their zero tax level. From 10 to 30 cents per pound, further reductions are projected to be minimal.

4.6.4 Costs

The total cost to the primary nonferrous smelting industry are shown in table 26 for selected tax rates. As graphically shown in figure 28, the total cost to the industry, comprising control costs and tax payments, increase at a generally decreasing rate. This is because of the high levels of emissions control induced by the tax.

These costs are shown on a per-unit-of-product basis in figure 29, assuming a perfectly inelastic demand for the three metals, and exclusive of the impacts the corporate income tax may have on costs. For reference, the 1970 average values of copper, zinc, and lead were $1,259, $306, and

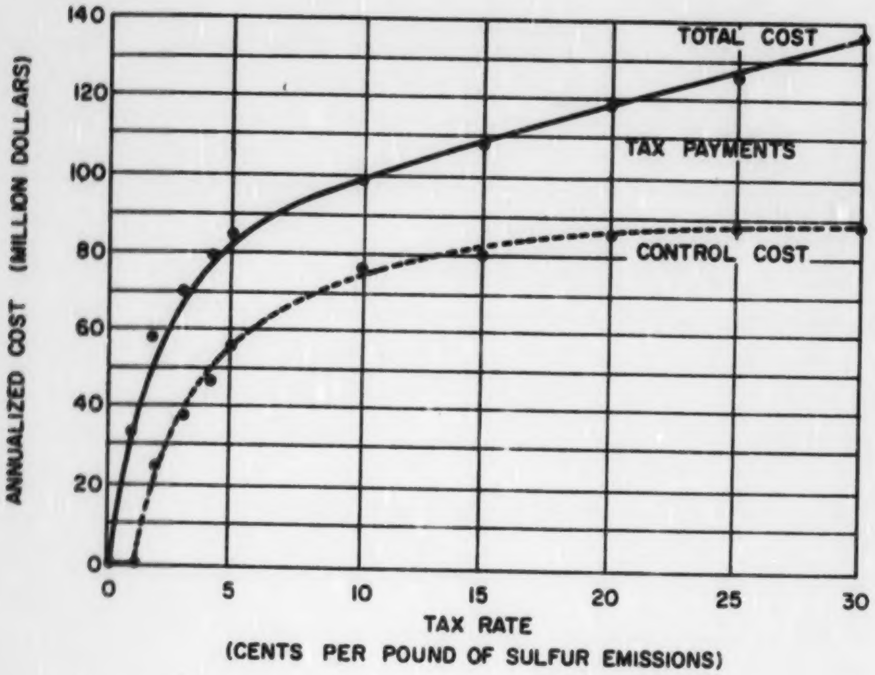

Figure 28. Total costs induced by a tax on sulfur emissions--1978 (Source: Research Triangle Institute).

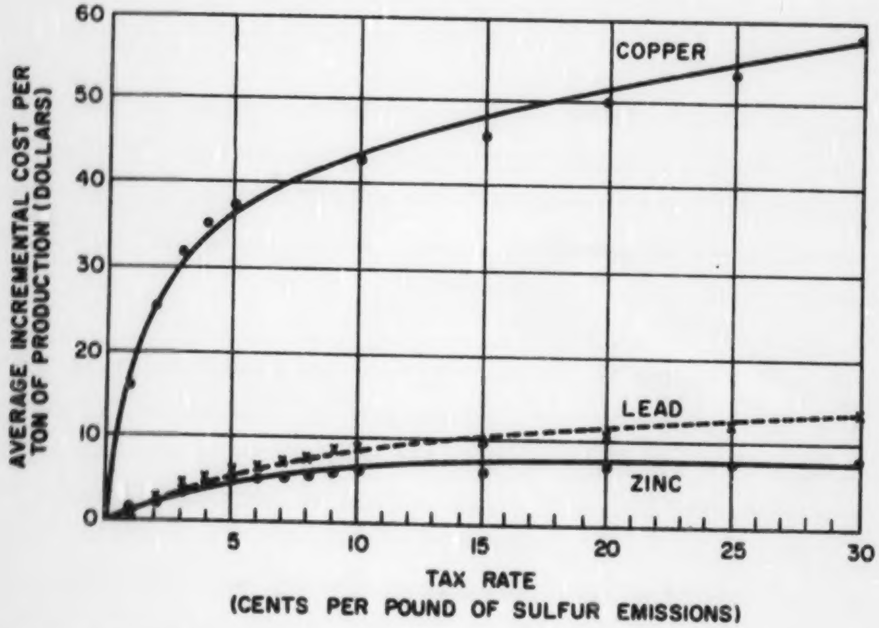

Figure 29. Average total* incremental costs per ton of product induced by a tax on sulfur emissions--1978 (*control cost plus tax payments) (Source: Research Triangle Institute).

$275 per ton, respectively. It appears that at tax rates sufficient to induce control of 94 percent of potential emissions (10 cents), the effect on product prices would be minimal, particularly for lead and zinc.

4.6.5 Sensitivity Analysis

The projected effectiveness and costs of a tax on sulfur emissions of primary nonferrous smelters is influenced not only by the tax rate but also by the assumed market value of the recovered sulfur and the estimated control costs of the sulfur emissions control alternatives. To examine the sensitivity of the projected effectiveness and costs to the assumed future value for recovered sulfur and to the cost estimates presented in appendix D, the percentage deviations in emissions and total costs caused by changes in the value of sulfur and control costs have been examined.

As shown in figure 30, if the sulfuric acid recovered by smelters could be sold at $10 per ton, rather than $0 as used above, the difference in total costs would be fairly significant. Because of the large amounts of sulfur emissions from nonferrous smelters and because of the relatively economical methods for emissions control, sale of the recovered acid at

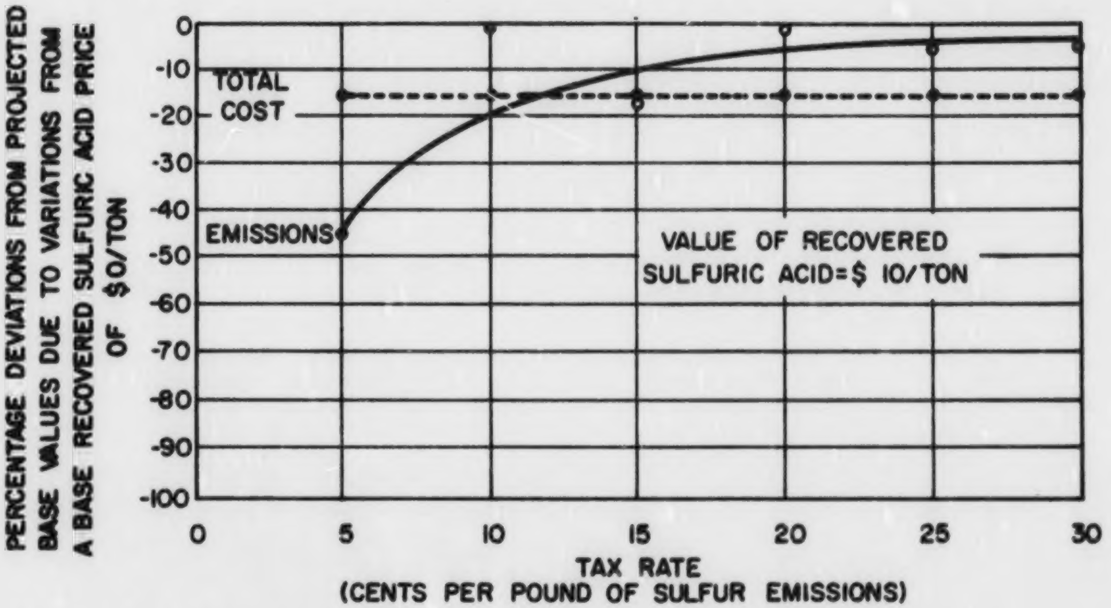

Figure 30. Sensitivity of the effectiveness and total costs of a tax on sulfur emissions to the value of recovered sulfur--1978 (*The base values refer to both the total control costs and the emission levels that obtain when recovered sulfur is worthless) (Source: Research Triangle Institute).

$10 per ton would reduce the costs induced by the tax. Lower costs would also mean lower emissions. For example, at a tax of 5 cents, and a $10 per ton value for recovered sulfur, emissions would be about 45 percent less and total costs 15 percent less than that projected, assuming the recovered sulfur was worthless.

The sensitivity of the emissions and total costs projections to changes in the control costs estimates of ±5, 10, and 20 percent are presented in table 27. Emissions are significantly different from those projected using the cost estimates presented in appendix E for tax rates of only 15 cents and for increases in the control costs of 10 to 20 percent.

Because the schedules of marginal emissions reduction costs, in some cases, are perfectly inelastic over certain ranges of costs, it is possible that what would otherwise appear as unusual predictions would in fact occur. An example of the effect of this inelasticity may be noted in the presence of a 10-percent decrease in control cost estimates (see table 27); a 10- and a 15-cent tax fail to induce additional emissions reductions above those projected (because the marginal cost curve is vertical over that range) but a 20-cent tax stimulates a 2-percent further reduction in emissions (because the marginal cost curve becomes more elastic in that neighborhood of costs). Total control related outlays are never more than 10 percent different from those projected under the assumed regime of control costs unless those costs are raised or lowered 20 percent or more.

Table 27. Sensitivity of effectiveness and total cost of tax on sulfur emissions to control cost estimates: primary nonferrous smelters--1978

Change in all control cost estimates (percent)	Change in emissions (percent)						Change in total cost (percent)					
	Tax rate (cents per pound of sulfur emissions)						Tax rate (cents per pound of sulfur emissions)					
	5	10	15	20	25	30	5	10	15	20	25	30
+20	1.7	0.0	12.2	16.5	2.3	0.5	13.4	15.5	14.5	14.0	13.7	12.9
+10	0.0	0.0	8.2	8.7	0.0	0.0	6.7	7.8	7.4	7.1	6.8	6.5
+ 5	0.0	0.0	0.0	2.7	0.0	0.0	3.4	3.9	3.7	3.6	3.4	3.2
- 5	-16.6	0.0	0.0	0.0	-0.5	0.0	-3.4	-3.9	-14.5	-3.6	-3.4	-3.2
-10	-30.0	0.0	0.0	-2.2	-0.5	-6.1	-7.3	-7.7	- 7.4	-7.2	-6.8	-6.5
-20	-50.0	-3.8	-9.4	-2.2	-0.5	-6.1	-15.7	-15.5	-14.9	-14.6	-13.7	-13.2

Source: Research Triangle Institute.

Chapter 5: IMPACT OF SULFUR TAX ON AIR QUALITY IN TWO HYPOTHETICAL AIR QUALITY CONTROL REGIONS

5.1 Introduction

This chapter briefly examines the effect of a sulfur tax on ambient sulfur dioxide (SO_2) concentrations in two hypothetical Air Quality Control Regions (AQCR's). A proportional model is used to relate annual sulfur emissions to annual arithmetic mean SO_2 concentrations. This model assumes uniform air quality across a region and a proportional relationship between changes in emissions and air quality. It is recognized that air quality varies across most regions; quality varies according to location and temporal and climatic conditions. The use of the proportional model here is only expositional; diffusion modeling is required to predict the distribution of air quality within a region. The effects of several sulfur tax rates on emissions and on SO_2 concentrations are compared, and the required tax rates to achieve the National Ambient Air Quality Standards for SO_2 in each region are determined.

5.2 Relationship between SO_2 Concentration and Sulfur Emissions

Assuming ambient pollutant concentration proportional to pollutant emissions, the concentration, C, resulting from a reduction in emissions is given by:

$$C = C_p (1 - r) \tag{1}$$

where C_p is the initial ambient pollutant concentration and r is the reduction in emissions expressed as a decimal percent.

Similarly, emissions after reduction, E, can be obtained from:

$$E = E_p (1 - r) \tag{2}$$

where E_p is initial emissions and r is defined above.

If an ambient air quality standard, C_s, is specified:

$$C_s = C_p (1 - r) \ , \tag{3}$$

then this equation, upon dividing both sides by C_p and changing signs, gives the familiar proportional equation:

$$\frac{C_p - C_s}{C_p} = r \ . \tag{4}$$

Thus, Eq. 1 can be used to calculate a new pollutant concentration resulting from a reduction in emissions, Eq. 2 can be used to calculate the emissions corresponding to a specified decimal percent reduction, and Eq. 4 can be used to calculate the required decimal percent reduction in emissions to achieve a specified ambient air quality standard.

5.3 Hypothetical AQCR's

5.3.1 Hypothetical AQCR A

This AQCR contains a petroleum refinery, a sulfuric acid plant, and point and area combustion sources of sulfur emissions including steam-electric power plants. Estimated annual uncontrolled sulfur emissions are 568,301 tons. Table 28 shows the distribution of emissions by source. The annual arithmetic mean SO_2 concentration is 0.085 ppm.

Table 28. Sulfur emissions by source for two hypothetical
Air Quality Control Regions*
(tons per year)

Source	Uncontrolled	Tax Rate (cents per ton of sulfur emissions)					
		5	10	15	20	25	30
AQCR A							
Petroleum refineries	47,597	40,750	35,845	34,079	34,079	34,079	34,079
Sulfuric acid plants	11,294	11,294	3,298	1,357	1,295	1,094	1,094
Primary nonferrous smelters							
Lead	0	0	0	0	0	0	0
Zinc	0	0	0	0	0	0	0
Copper	0	0	0	0	0	0	0
Stationary combustion	509,410	182,157	105,975	79,227	61,817	61,553	56,847
Total	568,301	234,201	145,118	114,663	97,191	96,726	92,020
AQCR B							
Petroleum refineries	19,776	17,083	15,539	14,690	14,465	14,465	14,465
Sulfuric acid plants	13,265	13,265	2,345	1,670	1,435	1,435	1,368
Primary nonferrous smelters							
Lead	10,373	10,373	10,373	2,581	2,581	2,581	2,581
Zinc	781	781	79	79	79	79	79
Copper	0	0	0	0	0	0	0
Stationary combustion	450,393	148,203	85,948	68,532	66,236	45,072	42,463
Total	494,588	189,705	114,284	87,552	84,796	63,632	60,956

*These are representative of large metropolitan regions.

5.3.2 Hypothetical AQCR B

This AQCR contains a primary nonferrous smelter, a petroleum refinery, a sulfuric acid plant, and point and area combustion sources of sulfur emissions including steam-electric power plants. Estimated annual uncontrolled sulfur emissions are 494,588 tons. Table 28 shows the distribution of emissions by source. The annual arithmetic mean SO_2 concentration is 0.047 ppm.

5.4 Effect of Sulfur Tax on Emissions and Ambient SO_2 Concentrations

5.4.1 Sulfur Emissions

The relationship between annual sulfur emissions and tax rate for the two hypothetical ACQR's is shown in figure 31. Annual sulfur emissions and the decimal percent reduction in annual sulfur emissions associated with each tax rate, as well as the annual sulfur emission and decimal percent reduction required to achieve the National Ambient Air Quality Standards for SO_2 (0.03 ppm annual arithmetic mean), are shown in table 29.

5.4.2 Ambient SO_2 Concentrations

The reductions associated with each tax rate in table 29 and the initial SO_2 concentrations were substituted in Eq. 1 to calculate the

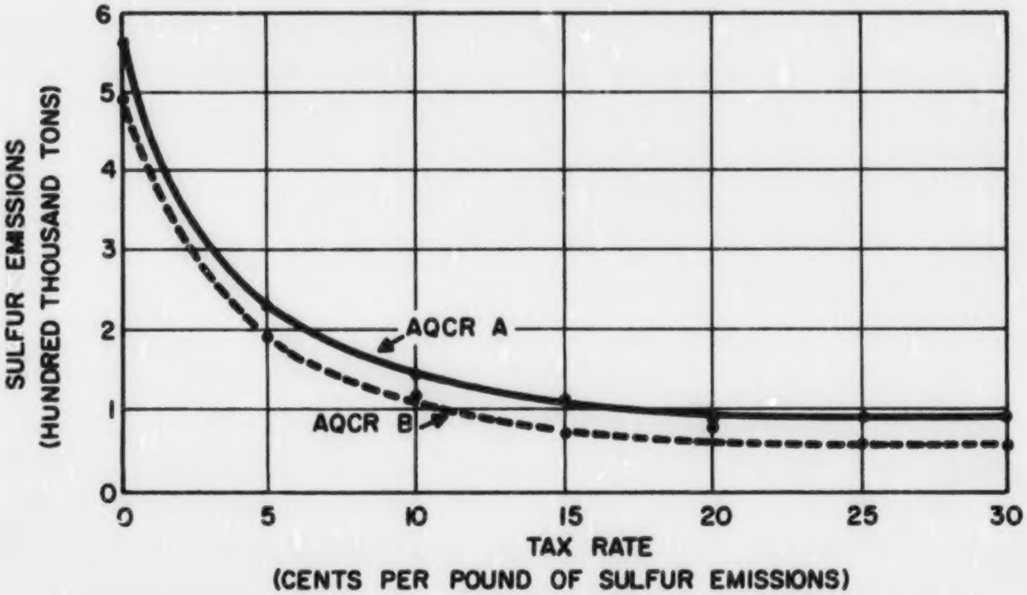

Figure 31. Effectiveness of a tax on sulfur emissions for two hypothetical Air Quality Control Regions (Source: Research Triangle Institute).

Table 29. Annual sulfur emissions and percent reduction with various tax rates

	Tax rate (cents per pound of sulfur emissions)							To achieve ambient air quality standard
	0	5	10	15	20	25	30	
Hypothetical AQCR A								
Annual sulfur emissions (tons/year)	568,301	234,201	145,118	114,663	97,191	96,726	92,020	198,905*
Reduction (decimal percent)	0	0.59†	0.75	0.80	0.83	0.83	0.84	0.65‡
Hypothetical AQCR B								
Annual sulfur emissions (tons/year)	494,588	189,705	114,284	87,552	84,796	63,632	60,956	316,536*
Reduction (decimal percent)	0	0.62†	0.77	0.82	0.83	0.87	0.88	0.36†

*Calculated from Eq. 2.

†Calculated by rearranging Eq. 2 and solving for r.

‡Calculated from Eq. 4.

corresponding annual arithmetic mean SO_2 concentrations which are plotted in figure 32. Inspection of figure 32 indicates that the standard would be achieved at tax rates approximating 6 and 2 cents per pound of sulfur in AQCR's A and B, respectively.

The simplified analysis presented herein illustrates the relationship between sulfur emissions and ambient SO_2 concentrations and the effect of increasing sulfur tax rates on both. However, it must be remembered that the assumed proportionality describes air quality in terms of one concentration, which is assumed to prevail throughout the AQCR. Since the sulfur tax would permit each source to select a cost minimizing mix of tax payments and emission control expenditures, the air quality standard may be exceeded in the vicinity of some sources if the tax rate is too low. To adequately explore the regional effects of a sulfur tax, it would be necessary to employ a diffusion model capable of examining the influence of individual sources on air quality.

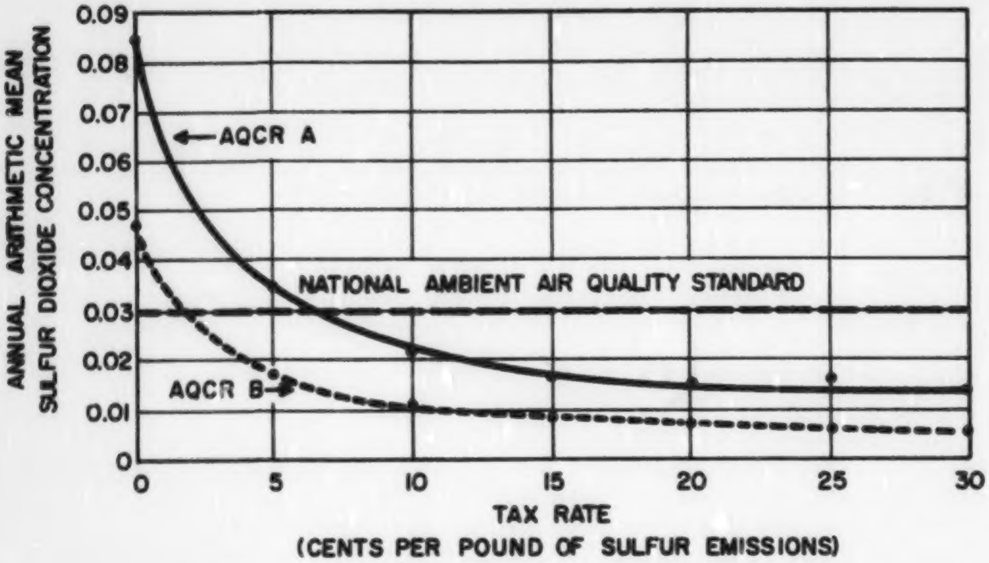

Figure 32. Relationship between tax rates and air quality for two hypothetical Air Quality Control Regions (Source: Research Triangle Institute).

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Appendix A: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR FUEL COMBUSTION SOURCES

This appendix describes the emission factors used, the sulfur emissions sources examined, and the control alternatives costed as part of the research presented in the text for steam-electric power plants and area sources.

A.1 Emission Factors

In the absence of controls, essentially all the sulfur contained in fossil fuels is emitted as sulfur oxides. The amount of sulfur emissions depends upon (1) the quantity of fuel consumed and (2) the quantity of sulfur per unit of the consumed fuel.

For both the steam-electric power plants and the area sources, the quantity of fuel consumed is based on projections of the demand for heat energy expressed in Btu. Projections of the national demand for electricity developed by the Edison Electric Institute* have been used to project the demand for Btu by steam-electric power plants. The 1970 Btu consumption by the area sources on a State-by-State basis have been continued to 1978 using projected population growth rates to project residential fuel consumption and projections of employment growth rates to derive projections of commercial and residential fuel consumption.† The estimated 1970 consumption of fuels by State and source are shown in table A.1.

The sulfur content of fuels is normally expressed as a percent by weight. The amount of sulfur emitted per ton of fuel is 20 lb for each 1 percent of sulfur content in the fuel. For example, a typical coal of 3.5 percent sulfur count releases 70 lb of sulfur per ton during combustion. Similarly, for residual oil weighing 7.88 lb per gal, 1 percent sulfur oil emits 0.0788 lb of sulfur per gal. Sulfur emissions per unit of heat contained vary with the heat content of the fuel. The heat content of coal varies significantly depending on the specific coal. For residual oil and gas, there is little variability. Data on the fuels and their heat contents are presented in the section on control alternatives.

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*Edison Electric Institute. Fuels for the Electric Utility Industry, 1971-1985, New York, Edison Electric Institute, 1972.

†U.S. Department of Commerce, Survey of Current Business, Vol. 52, No. 4, April 1972, p. 22-48.

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Table A.1. Area source fuel consumption by State, 1970

State	Residential		Commercial				Industrial			
	Distillate oil (thousand bbl)	Gas (million ft^3)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft^3)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft^3)
Maine	8,547	3,400	15	1,072	1,461.6	970.9	135.4	643.2	2,703.9	681.8
New Hampshire	6,279			693	659.4			415.8	1,219.9	
Vermont	4,293			591	200.7			354.6	371.3	
Massachusetts	46,243	53,400	57	7,014	19,011.3	14,471.7	293.3	4,208.4	35,170.9	7,789.9
Rhode Island	6,640	7,400	Included with Me., N.H., Vt.	847	1,404.8	1,905.9	Included with Me., N.H., Vt.	508.2	2,598.9	2,159.5
Connecticut	16,399	19,800	1	3,501	2,901.8	4,892.4	251.1	2,160.6	5,368.3	5,477.9
New York	76,637	225,300	80	18,106	36,451.8	58,269.8	5,659.6	10,863.6	67,435.8	39,746.4
New Jersey	38,743	98,900	8	12,883	8,367.4	17,777.3	450.1	7,729.8	15,479.7	26,933.6
Pennsylvania	37,327	200,600	600	6,160	8,265.5	46,331.5	7,711.9	3,696.0	15,291.2	119,294.0
Delaware	2,992	5,100	70	307	315.9	1,338.8	1,168.9	184.2	584.4	4,188.5
Maryland	11,346	57,400		1,428	3,134.8	16,410.4		856.8	5,799.4	14,324.1
Dist. of Columbia	2,583		70	464	5,055.1		375.3	278.4	9,351.9	
Virginia	11,507	31,700	500	1,313	1,006.5	12,217.6	4,000.9	787.8	1,862.0	14,799.4
West Virginia	295	38,300	250	32	342.2	9,680.9	4,936.1	19.2	633.1	31,913.7
North Carolina	12,148	18,900	500	1,131	679.5	8,668.2	2,001.5	678.6	1,257.1	24,566.2
South Carolina	3,961	12,400	300	442	154.9	6,108.8	1,300.0	265.2	286.6	27,281.1
Georgia	1,936	59,800	160	169	1,150.5	19,469.0	526.9	101.4	2,128.4	50,037.8
Florida	3,929	7,900		351	833.3	10,602.1		210.6	1,541.6	31,668.4
Michigan	24,368	226,600	900	2,079	899.8	67,759.4	7,922.6	1,247.4	1,664.6	100,399.6
Ohio	14,156	301,400	1,500	1,466	298.9	82,459.5	14,601.1	879.6	552.9	128,687.7
Indiana	15,056	106,600	600	1,416	1,748.9	36,922.9	6,418.4	849.6	3,235.5	94,407.6

Table A.1. Area source fuel consumption by State, 1970 (continued)

State	Residential		Commercial				Industrial			
	Distillate oil (thousand bbl)	Gas (million ft^3)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft^3)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft^3)
Illinois	19,601	295,200	2,800	2,550	8,873.1	97,085.4	7,741.3	1,530.0	16,415.2	125,555.9
Wisconsin	17,417	68,800	1,600	1,919	599.6	21,472.9	4,096.7	1,151.4	1,109.3	44,934.8
Minnesota	13,456	65,000	900	1,118	605.7	24,231.6	1,584.2	670.8	1,120.5	32,467.8
Iowa	6,340	62,000	200	467	158.6	27,537.7	1,694.9	280.2	293.4	31,735.9
Missouri	1,145	103,200	100	620	1,225.5	35,625.5	1,615.9	372.0	2,267.2	35,287.4
Kansas	530	64,100	60	44	262.9	24,664.1	227.4	26.4	486.4	54,919.6
Nebraska	1,866	37,500		158	79.3	18,216.1		94.8	146.7	17,606.1
South Dakota	2,572	8,800	200	146	9.2	4,779.0	473.2	87.6	17.0	2,194.2
North Dakota	2,617	5,200		220	42.1	3,667.1		132.0	77.9	981.8
Kentucky	1,950	57,000	500	182	70.8	17,352.7	2,199.6	109.2	130.9	22,973.7
Tennessee	1,679	30,900	600	148	9.2	19,994.8	2,229.5	88.8	17.0	41,021.8
Alabama	566	37,300	100	53	47.6	18,809.7	1,767.6	31.8	88.1	60,727.8
Mississippi	629	20,600		58	29.9	8,015.7		34.8	55.3	43,348.9
Arkansas	449	39,700	4	40	-	20,064.2	113.7	24.0	-	51,774.5
Louisiana	618	56,400		57	9.8	17,320.4		34.2	18.1	337,363.9
Oklahoma	523	51,200		35	100.7	19,195.0		21.0	186.3	40,691.0
Texas	2,470	150,100		157	337.9	48,797.6		94.2	625.1	599,958.5
Montana	970	14,600	250	37	111.6	7,546.7	161.4	22.2	206.5	11,170.9
Idaho	2,792	4,700		178	71.9	2,822.3		106.8	133.0	8,919.8
Wyoming	581	11,300	20	52	207.4	6,626.1	212.2	31.2	383.7	14,932.8
Colorado	1,170	55,100	300	53	208.0	26,946.8	441.4	31.8	384.8	30,338.7
Utah	1,064	29,900	160	125	407.5	4,995.3	454.8	75.0	753.9	21,223.7

Table A.1. Area source fuel consumption by State, 1970 (continued)

State	Residential		Commercial				Industrial			
	Distillate oil (thousand bbl)	Gas (million ft^3)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft^3)	Coal (thousand tons)	Distillate oil (thousand bbl)	Residual oil (thousand bbl)	Gas (million ft^3)
Nevada	691	4,300	5	89	24.4	2,425.8	20.1	53.4	45.1	3,428.6
New Mexico	275	19,100	2	19	1.8	7,998.2	115.1	11.4	3.3	23,516.9
Arizona	37	19,300	5	7	8.5	8,861.1	20.1	4.2	15.7	20,528.9
Washington	10,982	20,700	100	813	2,274.7	8,979.8	30.8	487.8	4,208.2	32,317.3
Oregon	5,793	13,900		437	2,017.3	5,281.5		262.2	3,732.0	18,644.9
California	1,274	382,200	10	91	1,453.6	107,561.4	14.4	54.6	2,689.2	206,412.5
Alaska	2,080	3,100	30	161	21.4	2,765.5	480.0	96.6	39.6	4,778.6
Hawaii	169			9	155.6			5.4	287.9	
Total	447,691	3,206,100	13,557	73,650	113,812.0	1,035,900.0	210,552.0	83,490.0	44,190.0	2,664,100.0

Source: Research Triangle Institute.

A.2 Sulfur Emissions Control Alternatives and Costs

There are two classes of control alternatives: (1) removal of sulfur oxides from stack gases and (2) use of low-sulfur fuels (fuel switching). Gas cleaning is technologically more complex, while use of low-sulfur fuels has economic and resource availability complexities. In this study, gas cleaning is considered only for the steam-electric power plants and not for area sources because of the lack of data on boiler sizes and distributions.

A.2.1 Sulfur Oxide Removal from Stack Gases

Sulfur oxide removal from stack gases may be accomplished by adsorption by a dry or wet medium. For both wet and dry, there are regenerable processes (in which the sorbent is regenerated for reuse with a concentrated sulfur-bearing byproduct stream) and throwaway processes (in which the sorbent is discarded along with the captured sulfur values). Of the many processes and process variants currently in various stages of development and/or demonstration and utilization, three were selected for this analysis because it appears that they will be available by 1978: (1) dry limestone adsorption, (2) wet limestone slurry scrubbing, and (3) magnesium oxide (magnesia base) solution scrubbing. These three techniques were chosen because they are respresentative of a range of control costs and efficiencies.

A discussion of each of these control techniques follows. Their costs are based on EPA studies. The control efficiencies of the three systems costed are summarized in table A.2. The costs are summarized in table A.3.

Table A.2. Steam-electric plant sulfur emissions stack gas control alternatives

Emissions source	Alternative	Description	Removal efficiency (percent)	Input sulfur recovered (percent)
Coal-burning boiler	1	Dry limestone	35	0
	2	Wet limestone	85	0
	3	Magnesia base	95	92*
Oil-burning boiler	1	Dry limestone	55	0
	2	Wet limestone	85	0
	3	Magnesia base	95	92*
Gas-burning boiler	None	--	--	--

*Some sulfur is lost in the bleed stream from magnesia base regenerator which is used to remove impurities.

Source: Research Triangle Institute.

Table A.3. Sulfur emissions control cost equations for steam-electric utilities using flue gas desulfurization

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$$(1)\quad C_i = (370{,}000)^{(B_i)(S)}\left[\frac{785.33}{(L\cdot A\cdot M)^{0.28}} + \frac{10.87}{(L\cdot A\cdot M)^{0.57}}\right] + \left[\frac{F_i\cdot S}{M}\right]$$

where:

C_i = total annualized cost of control, 10^9 Btu
L = boiler load factor
A = boiler annual hours
M = boiler capacity in megawatts
S = sulfur content of fuel
$B_1 = 9.0$ 1 = coal burning
$B_2 = 5.4$ 2 = oil burning
$F_1 = 2071.4$
$F_2 = 1240.0$

$$(2)\quad C_j = \left[\frac{162{,}000\,(Z + B_i\cdot S^{0.67}\cdot M^{0.02})}{M^{0.35}}\right]\left[\frac{0.175}{L}\right] + \left[\frac{F_i\cdot S + 1.8}{A}\right]$$

where:

C_j = total annualized cost of control 10^9 Btu, j = 1 or 2
L = boiler load factor
A = boiler annual hours
M = boiler capacity in megawatts
S = sulfur content of fuel
$B_1 = 28{,}600$ 1 = wet limestone
$B_2 = 40{,}400$ 2 = magnesia base
$F_1 = 1.850$
$F_2 = 0.440$
$Z = [M/150]$ if $M/150 = [M/150]$
$[M/150] + 1$ otherwise as: [ ] = "the integer part of"

Sources:

Hittman Associates, Inc., Cost Nomographs of Selected Sulfur Dioxide Abatement Methods, Contract No. EHSD-71-43 for Environmental Protection Agency office of Air Programs, Columbia, Md., 1972.

John K. Burchard et al., Some General Economic Considerations of Flue Gas Scrubbing for Utilities, Environmental Protection Agency, Research Triangle Park, N.C., 1972. Also: Private communication with Gary Rochele at EPA.

A.2.1.1 Dry Limestone Adsorption. The dry limestone adsorption system is a low-efficiency (35 to 55 percent control) sulfur oxide collection alternative.

The basic steps involved in this process are (1) grinding limestone to a fine-grained powder, (2) injecting it into the combustion chamber, and (3) collecting the reacted limestone products which then contain sulfur along with other particulates in a high-efficiency electrostatic precipitator.

Pilot plant operation has revealed several problems with dry limestone removal of sulfur oxides which should be mentioned. First, the limestone is not utilized efficiently because the sulfur oxides cannot penetrate into the interior of the particles of lime (calcined limestone). This problem may be accentuated by fly ash coating the surface of the lime particles, particularly in coal-burning boilers, and by fusing of the lime particles (dead-burning) if the grains are overheated in the boiler. Inefficient use of the limestone can be partially overcome by injection of additional limestone. However, this causes additional expense because (1) more limestone must be used, (2) more fuel must be used to calcine the limestone (releasing more sulfur oxides), and (3) additional precipitator capacity and waste disposal handling are required.

A second problem is that under certain conditions some of the initially collected sulfur oxides may be re-released into the gas stream after having been adsorbed. Third, the limestone, lime, and sulfite/sulfate become an added particulate burden. Fourth, the collection efficiency of standard fly-ash electrostatic precipitators is reduced because sulfur oxides, which enhance the efficiency of a precipitor, are reduced.

A.2.1.2 Wet Lime Scrubbing. The chemical reaction involved in wet lime scrubbing is the same as for dry limestone adsorption, namely converting gaseous sulfur oxides to calcium sulfite/sulfate. The reaction takes place in the scrubber, however, rather than in the combustion chamber. The combustion gasses are ducted through a scrubber where they are washed by slurry of water and lime or limestone, resulting in removal of approximately 85 percent of the sulfur oxides (the factor used in this study). Wet lime scrubbing is considerably more economical of lime than dry limestone scrubbing, requiring as little as 10 percent above the theoretical minimum. However, investment costs are higher for the (usually multiple) wet scrubbers and scrubbing solution handling equipment. Higher costs also result from spent slurry disposal and control, added fuel costs (or lowered generating efficiency) to restore stack gas temperatures lowered by the scrubbing, and additional operation and maintenance costs for the more complex system.

There are three methods of introducing lime into the scrubbing system. In one method, limestone is injected into the boiler in the same manner as the dry limestone process, but a scrubber is used as the collector. In a second method, limestone is introduced into the scrubbing liquor. In a third method, which has been assumed in this study, precalcined lime is introduced into the scrubbing liquor. Introduction of lime into the scrubbing liquor (slurry) reduces the amount of slurry to be handled and utilizes a greater percentage of the calcium input values since lime is more reactive than limestone, while avoiding the plugging and scaling problems resulting from injecting limestone into the boiler.

The total scrubbing system includes the scrubber(s), the scrubbing liquor handling circuit(s), the reheat system, and the associated ductwork and piping. In addition, some sort of slurry disposal system must be included.

The scrubber design assumed in this system is a floating bed (ping-pong ball) scrubber. The maximum gas throughput for which these scrubbers can be designed is currently 300,000 ft^3/min, which approximates the gas flow of a 150 MW generating plant. Therefore, further technological economies of scale do not exist for plants of greater than 150 MW capacity. However, some cost savings are possible with the use of multiple units because volume discounts are usually offered and because there is usually some relative savings in installation costs. The scrubbing slurry handling equipment must be designed to adjust lime usage and slurry pH for scrubbing optimization. One slurry handling system is therefore required for each scrubbing unit.

The flue gas reheat system is designed to raise the temperature of the scrubbed gases to provide adequate plume rise. This can be done with a single system for each boiler rather than a separate system for each scrubber.

Disposal of waste slurry is assumed to be by discharge to a pond for settling, with overflow to sewers or a watercourse. Expenses related to water pollution control from the pond overflow or to ultimate disposal of the dewatered slurry waste have not been included.

A.2.1.3 Magnesia Base Scrubbing. The entire magnesia base scrubbing system, including stack gas reheating, is identical in concept to lime scrubbing. Some simplification of the scrubbing liquor handling system is possible, however, because the liquor is more nearly a solution of magnesium oxide and hydroxide, rather than a slurry such as with limestone or lime. This factor also allows a higher control efficiency than for lime scrubbing, typically 95 percent. However, the high cost of the magnesium oxide reagent and the ease of regenerating it impose additional equipment requirements for economical operation.

The first addition is a thermal decomposition system which dries the magnesium sulfite/sulfate solution and subsequently drives off sulfur dioxide, leaving the magnesium oxide to be reused. A small amount of the magnesium oxide (typically 2 percent of the total throughput) is discarded to prevent buildup of the trace impurities removed from the gas stream during scrubbing. The purified, concentrated sulfur oxide gas stream must then be treated in some way. Among the alternatives which yield marketable byproducts are (1) compression and liquefaction to product liquid sulfur dioxide for sale, (2) conversion to elemental sulfur in a Claus unit using natural gas or some other hydrogen source, or (3) conversion to sulfuric acid in a (contact) sulfuric acid plant. Conversion to sulfuric acid has been chosen for this study since sulfuric acid is a more saleable byproduct than liquid SO_2 and because acid manufacture does not require a hydrogen source.

A.2.2 Fuel Switching

Sulfur emissions from fuel combustion are in direct proportion to the sulfur content of the fuels. Since the sulfur content of coal and residual oil can be specified by customers when purchasing these fuels, there is the opportunity to reduce sulfur emissions by burning fuels of lower sulfur contents than those which would be selected in the absence of a tax on sulfur emissions. Gas has the lowest sulfur content per Btu of the three principal fuels and is therefore a particularly attractive alternative. However, gas supplies are currently limited due to a regulation-induced shortage.* Switching to low-sulfur fuels is the only control technique usually assumed available to area source combustion. For steam-electric power plants, fuel switching is an attractive alternative because it does not involve the use of new technologies that may not be completely proven.

Fuel switching costs consist of price premiums for low sulfur fuel and, whenever a fuel is used other than that for which the boiler was designed to burn, boiler conversion costs. In this study, a cost of $11 per billion Btu and $300 per megawatt have been used for area source and steam-electric boiler conversions, respectively.† Estimation of the fuel price structure under alternative tax rates would ideally involve the use of a general equilibrium-type of model of the demand and supply of fuels. Although development of such a model was beyond the scope of this study, it was possible to include a reasonably complex set of price and fuel supply conditions so that the role of prices in allocating fuels could be explicitly included if not completely satisfactorily modeled. Recent studies by MITRE‡ and Battelle§ provided a basis for developing projections for 1978 of maximum domestic production of coal and residual oils by source location and sulfur content and by minimum price levels sufficient to cover costs and to provide reasonable profit levels. The supply of imported residual oils is assumed to be perfectly elastic. Based on these prices plus the estimated transportation cost, cost functions have been developed for each fuel user. The analysis of fuel switching, as an alternative control system for steam-electric utilities and area sources, has been based on the fuel cost estimates with consumption of domestically produced fuels constrained by projected national production. It is recognized that the supply functions assumed for this study do not allow for the likelihood of shifts in supply over time due to increases in the prices of some fuels nor do they recognize the position of the United States as a consumer of the world's oil supply. However, over the relatively short time frame involved and considering the scope of this study, they represent a reasonable set of working assumptions.

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*MacAvoy, Paul W., "The Regulation-induced Shortage of Natural Gas," Journal of Law and Economics, Vol. 14, No. 1 (April 1971), pp. 167-98.

†Derived from data presented in Ehrenfeld, J.R. et al, Systematic Study of Air Pollution from Intermediate-size Fossil-fuel Combustion Equipment, Walden Research Corp., Cambridge, Mass., July 1971.

‡MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972.

§Battelle Memorial Institute, Energy Quality Model--1972, unpublished.

A.2.2.1 Coal. Coal is the major fuel for steam-electric power generation. The production of coal is from coal reserves that vary with respect to location, characteristics, and amount. Although total coal reserves are estimated to be about 2.9 trillion tons, only a small part of this total is precisely located ("known") and recoverable with current technology. These currently known recoverable reserves, estimated to be 50 percent of known reserves, are as follows: anthracite, 6,368 million tons; bituminous, 130,755 million tons; subbituminous and lignite, 59,931 tons.[*]

Known recoverable reserves of coal are unevenly distributed among the major coal-producing regions. The region with the largest share of these reserves is the Northern Rocky Mountain region (table A.4) which is, of course, located long distances from the nation's major population centers where most coal is consumed.

The sulfur content of coal, which is critical in determining emissions from coal combustion, varies by type of coal. All anthracite and most subbituminous coal and lignite reserves have low sulfur content (1 percent or less sulfur by weight). Almost one-half of all recoverable coal reserves, however, is bituminous coal whose sulfur content varies considerably. Most of the bituminous reserves (about 57 percent) are of high sulfur content (over 2.0 percent). Less than one-third of the reserves (about 30 percent) is of low (1 percent or less) sulfur content. The remainder of the bituminous coal reserves (about 13 percent) is estimated to be of medium (1.1 to 2.0 percent) sulfur content.

In 1970, the more than 5,000 active bituminous coal and lignite mines operating at an average of 82 percent capacity produced about 603 million tons.[†] However, not all of the 603 million tons are available for consumption by the steam-electric plants and area sources for the following reasons: (1) Most coal (71 percent) is cleaned to reduce impurities and enhance the Btu content; as a result about one-fourth of this tonnage becomes

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[*] MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, pp. 18-19.

[†] Minerals Yearbook, Vol I, U.S. Department of Interior, Bureau of Mines, p. 329.

Table A.4. Geographic distribution of known recoverable reserves of coal

Coal-producing region	Known recoverable reserves (billion tons)
Northern Appalachian	16
Southern Appalachian	12
Eastern Interior	62
Western Interior	10
Northern Rocky Mountains	80
Southern Rocky Mountains	17
West Coast	1
Total	198

Source: MITRE Corporation, Survey of Coal Availabilities By Sulfur Content, p. 18.

refuse. (2) Some coal is exported. (3) Finally, some coal is used to produce coke for blast furnaces and for the self-generation of power at steel and rolling mills. These so-called metallurgical coals, usually captive to the consuming industries, must have a property known as caking (or coking) and must be of low sulfur and ash content. As a result, they carry a price premium and should not be considered as possible fuels for consumption by the steam-electric power plants and the area sources. After all these adjustments have been made, MITRE estimates the production of commercial steam coal in 1970 to have been about 363 million tons.*

Table A.5 shows the estimated 1970 production of commercial coal, which is all noncaptive steam coal, by region and sulfur content. The regions east of the Mississippi River dominate production of all coals; however, western reserves of low sulfur coal are many times greater than those in the eastern regions.

Table A.6 shows maximum 1978 coal production levels. These estimates are given by region and sulfur content and assume current production costs.

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*MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, pp. 29-34.

Table A.5. Production of commercial bituminous and subbituminous coal--1970
(millions of tons)

Region or basin	≤ 0.7	0.8-1.0	1.1-1.5	1.6-2.0	2.1-2.5	2.6-3.0	3.1-3.5	3.6-4.0	> 4.0	Total
	Sulfur content (by weight, dry basis)									
Northern Appalachian	0.06	1.07	4.1	31	18	14	7.8	5.4	0.45	81.88
Southern Appalachian	17.00	46.00	16.0	14	4.3	0.22	2.2	0.0	0.0	99.72
Eastern Interior	0.96	--	7.8	9.2	3.7	7.4	47.0	51.0	19.0	146.06
Western Interior	0.33	0.19	0.34	0.12	0.14	0.56	0.56	0.64	5.2	8.08
Northern Rocky Mountains	12.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.3
Southern Rocky Mountains	12.7	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.4
West Coast	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Total United States	43.75	49.06	28.24	54.32	26.14	22.18	57.56	57.04	24.65	362.94

Source: MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, pp. 26-34.

Table A.6. Projected maximum production of commercial bituminous coal--1978
(millions of tons)

Region or basin	≤ 0.7	0.8-1.0	1.1-1.5	1.6-2.0	2.1-2.5	2.6-3.0	3.1-3.5	3.6-4.0	> 4.0	Total
	Sulfur content (percent, by weight, dry basis)									
Northern Appalachian	0.07	1.92	10.85	36.94	26.05	17.18	10.26	7.46	0.69	111.42
Southern Appalachian	26.4	54.98	20.19	16.03	4.85	1.17	2.2	0.01	0.03	125.86
Eastern Interior	1.04	0.85	13.71	14.49	8.17	27.22	86.56	102.68	40.25	294.93
Western Interior	0.36	0.33	0.82	0.35	1.97	0.94	2.78	6.41	17.48	31.45
Northern Rocky Mountains	49.17	31.86	0.05	0.48	0.11	0.05	0.01	---	0.16	81.89
Southern Rocky Mountains	34.82	19.92	0.04	0.38	0.0	0.0	0.0	0.0	1.00	56.16
West Coast	1.43	0.37	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.80
Total United States	113.29	110.23	45.66	68.67	41.15	46.56	101.81	116.56	59.61	703.51

Source: Developed from data in Survey of Coal Availabilities by Sulfur Content, MITRE Corporation, May 1972, pp. 26-34.

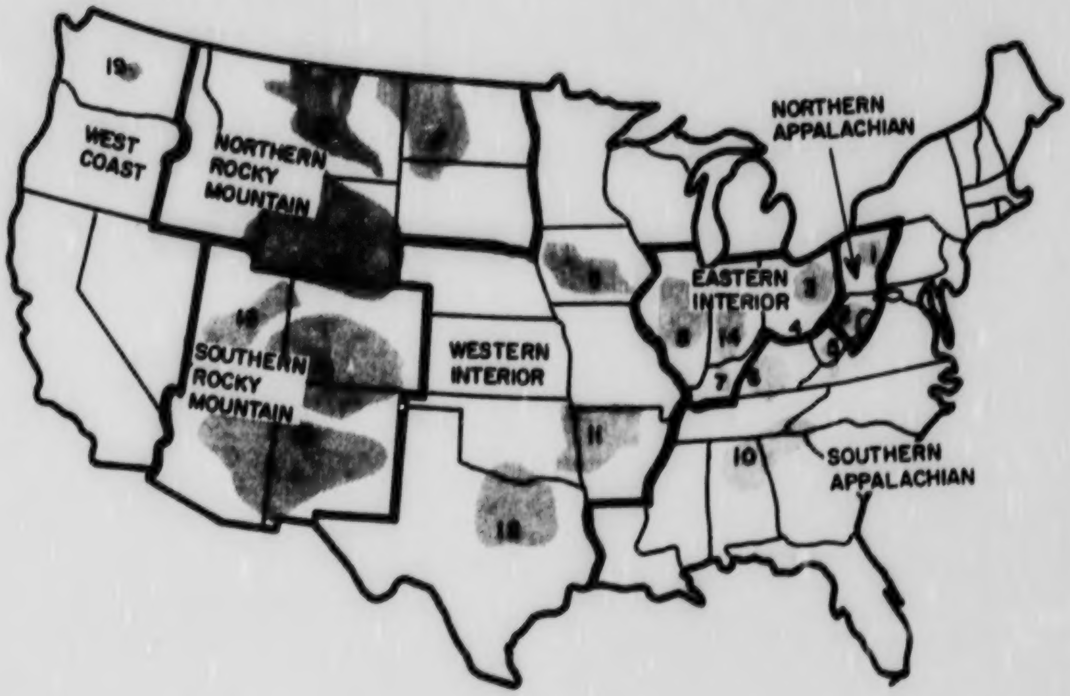
19
WEST COAST
NORTHERN ROCKY MOUNTAIN
16
SOUTHERN ROCKY MOUNTAIN
WESTERN INTERIOR
11
18
EASTERN INTERIOR
9
14
7
8
3
4
1
NORTHERN APPALACHIAN
10
SOUTHERN APPALACHIAN

Figure A.1. Coal-producing districts (Source: Department of the Interior).

They are based on the assumption that production growth will not occur unless it is maintainable for at least 20 years.*

These projections of 1978 production levels for the major coal-producing regions have been converted to Btu's. Projections of coal supply used by Battelle were employed here to derive proportions and the values in table A.5 across the 19 coal-producing districts (fig. A.1). It would require 4 years to attain the indicated levels in the eastern regions and 3 years in the western regions.† For purposes of this analysis, they have been used to provide upper limits on coal supplies.

Coal prices will influence fuel selections by the fossil fuel combustion sources. As shown in figure A.2, coal prices have recently been rising rapidly. In part, these price increases may be due to

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*MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, p. 79.

†MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, p. 81.

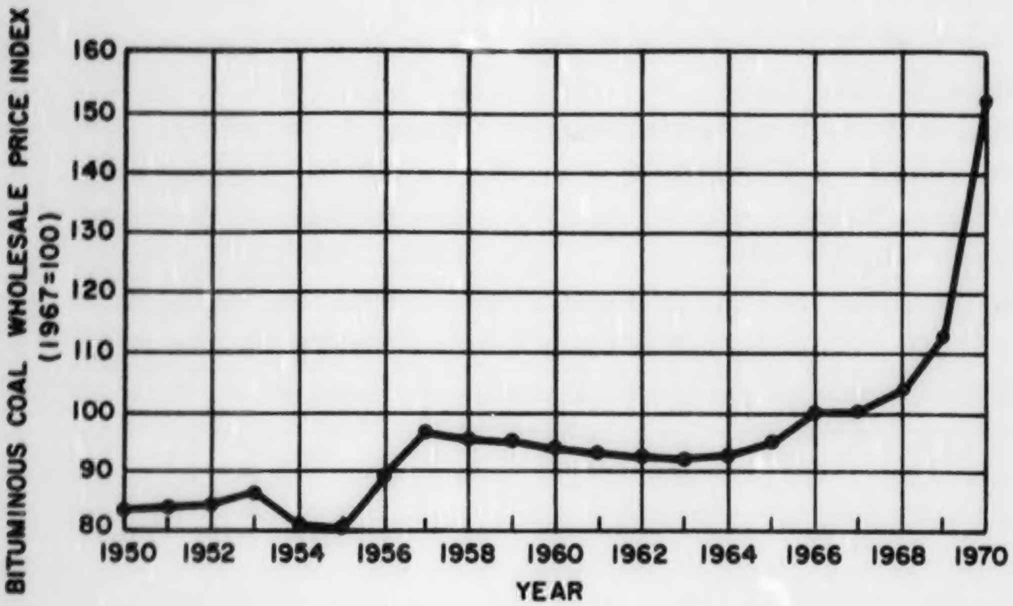

Figure A.2. Bituminous coal price trends (Source: Department of Labor).

increases in the demand for low sulfur coals as a result of air quality regulations. For this study it is desirable to have sets of fuel prices by sulfur content and location which reasonably reflect supply conditions from which to estimate fuel cost increases due to fuel switching.

Low sulfur coals are in limited supply in the Eastern United States, most deposits being in the Southern Appalachian Region. Western low sulfur fuels are more abundant but may have high delivered costs due to their distance from markets and their lower Btu content.

Initial estimates of the prices of all coals were derived from the Battelle study.* As they explain, however, their prices were minimum price estimates. Many prices may be bid upward in the presence of air quality regulations, regardless of whether emissions standards or taxes are used to induce compliance.

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*Battelle Memorial Institute, Energy Quality Model--1972, unpublished.

Using these estimates as a floor below which prices are not expected to go, the emissions response model was run to derive projections of steam-electric utilities demand for each coal type. Fuel demand and supply for each sulfur content were then compared on a national basis. When demand exceeded supply, the regions contributing to the excess were identified from the disaggregated district tables. Prices of fuels for which the demand exceeds supply were incremented and the model was rerun. Several iterations were required, until a price structure was developed that reflected market conditions. It is recognized that this approach is quite simplistic when compared with a more sophisticated approach such as linear programming (which would have resulted in a unique price structure). Such an approach, however, would have been beyond the scope of this study. For example, in this model each utility can select from among four control alternatives, (i.e., three hardware and one no-hardware), nine sulfur contents, and 19 regions for coal alone; a total of over 500 combinations exist. There are about 1,000 utilities. The linear programming model implied by the size of the model would have been substantial. Yet it was recognized that (1) the demand for these fuels was interrelated, (2) each utility faces a large number of alternatives (not merely "low sulfur" fuel as implied in many studies), and (3) relative fuel prices will be critical in the selection from among control alternatives. The approach employed in this study as discussed above does offer the opportunity to incorporate a fair degree of sophistication into the analysis of the response of fuel combustion sources to an emissions tax. The resulting price levels are presented in table A.7. For ease of calculation, an average sulfur content was used rather than a range as was presented earlier.

A.2.2.2 Oil. Distillate and residual fuel oils are important sources of energy for steam-electric utilities and for area heating sources. Domestic supplies of those fuel oils are functions of the supply of crude and production decisions on the proportion of the total that is to be refined into fuel oil versus other petroleum products. An increase in the share going to gasoline, for example, tends to reduce the availability of fuel oil.

Domestic supplies of residual and distillate oil have been insufficient to meet demand in recent years, as shown in figure A.3. As a result,

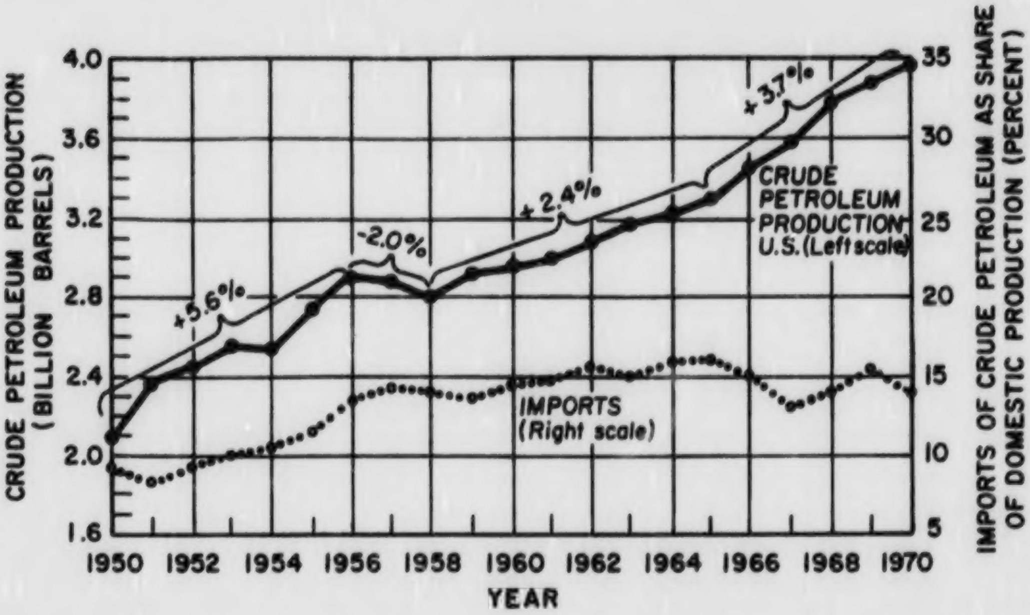

Figure A.3. Sources of supply of petroleum (Source: Department of Interior).

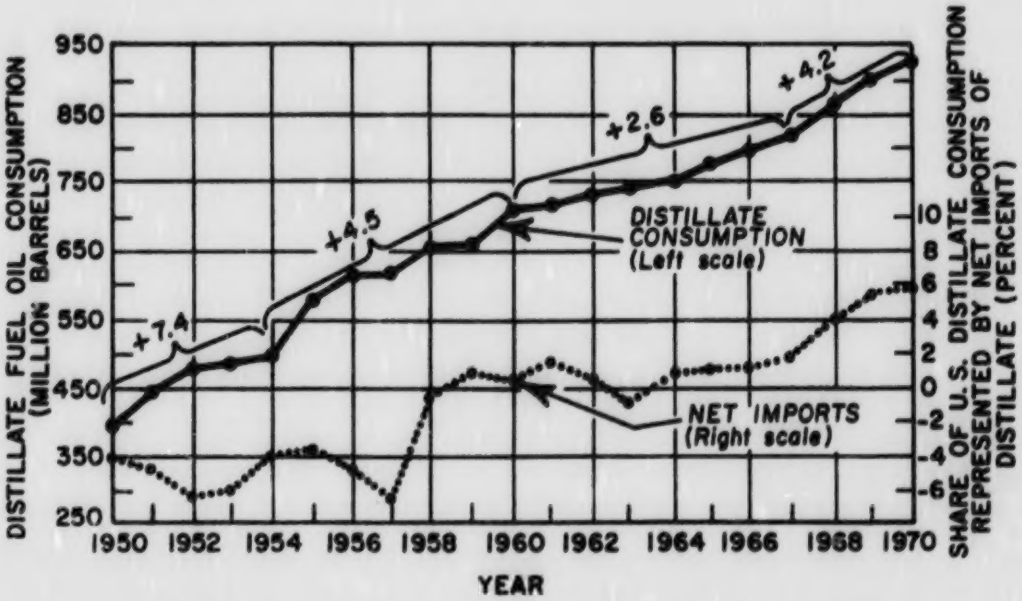

Figure A.4. Distillate consumption (Source: U.S. Department of Interior).

Table A.7. Coal prices by district
(dollars per billion Btu)

Coal district	Sulfur content (percent) 0.7	0.9	1.3	1.8	2.3	2.8	3.3	3.8	5.0
1	424	394	334	300	273	269	249	247	246
2	430	375	340	301	300	298	245	240	235
3	414	340	291	264	239	238	237	217	216
4	385	352	316	284	280	275	270	265	260
5	395	373	331	305	282	280	279	278	277
6	385	364	315	275	254	249	243	240	243
7	420	415	340	323	261	247	224	215	210
8	460	390	330	300	259	235	234	227	225
9	422	385	364	330	323	284	270	267	266
10	421	390	355	311	276	275	275	274	273
11	422	412	364	341	320	309	289	287	286
12	422	385	364	330	301	299	298	269	261
13	385	343	342	342	341	341	341	---	341
14	385	343	334	323	---	---	---	---	320
15	385	333	331	330	---	---	---	---	325
16	385	333	330	326	---	---	---	---	300
17	395	358	355	353	348	348	348	---	351
18	379	325	320	318	316	314	313	---	313
19	360	315	---	---	---	---	---	---	---

Source: Adapted from Battelle Memorial Institute, EPA Energy Quality Model, September 1972.

imports of both crude and refined oils have increased and do supply a substantial share of the market. Table A.8 shows the 1970 sources of residual fuel oil. The importance of imports and their country of origin are shown. The data may understate the role of the Middle East and overstate that of Europe, however, since some Middle East crude is refined in Europe and then shipped to the United States. Trends in the share of crude and residual oil imports from the Middle East are shown in Table A.9. A recent study* estimated that the import share of domestic consumption of fuel oil will double between 1970 and 1980.

A.2.2.2.1 Distillate. Distillate production represents a declining but substantial share of domestic oil production (figure A.4). While some distillate is used by steam-electric utilities for peak load power generation, it represents only a small energy source for these utilities. However, distillate is an important source of energy for the area sources where it is used as a power generating fuel and, more commonly, as a heating fuel.

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*National Petroleum Council, U. S. Energy Outlook, Vol. 2, November 1971, p. 57.

Table A.8. Sources of residual fuel oil, 1970

	(thousand barrels)
Domestic sources of supply	266,228
Production	257,510
Crude used directly as residual	4,317
Reductions in stocks	4,401
Domestic consumption	804,287
Exports	19,786
Imports	557,845
North America (Canada and Mexico)	14,147
Central America and Caribbean	261,299
South America	220,842
Europe	58,251
Middle East	1,554
Africa	1,616
Asia	136

Source: Minerals Yearbook, U.S. Department of the Interior, Bureau of Mines, 1970

Table A.9. Crude and residual oil imported
into the United States from the Middle East

	Crude oil		Residual oil	
Year	Amount (thousand barrels)	Share of Imports (percent)	Amount (thousand barrels)	Share of imports (percent)
1967	67,977	16.5	5,421	1.4
1968	72,330	15.3	4,431	1.1
1969	61,616	12.0	4,872	1.1
1970	61,892	12.8	1,554	0.3
1971	124,155	20.2	4,226	0.7

Source: Minerals Yearbook, U.S. Department of the Interior, Bureau of Mines.

No attempt has been made in this study to assess future supplies of distillate. The assumption has been made that distillate will be available in quantities sufficient to meet projected demands. For this study, it has been assumed that only area sources consume distillate fuel. The sulfur content is 0.10 pounds per million Btu regardless of origin, and consumers are assumed to have perfectly inelastic demand for distillate. Thus, it has not been necessary to develop any structure of prices since, for any tax rate, consumption will remain constant and tax payments made on emissions.

A.2.2.2.2 Residuals. Domestic production of residual oil provides only about one-third of consumption (fig. A.5). Residual fuel oils are a significant source of energy for steam-electric utilities. In 1970 they accounted for about 15 percent of total Btu's consumed.* While domestic production is limited, the supply of foreign residuals is assumed to be perfectly elastic.

MITRE† has provided projections of domestic residual oil production for the 5 PAD districts‡ (table A.10). In order to use the Battelle price and transportation data, these projections were distributed among 12 oil-producing regions (fig. A.6) using proportions derived from the Battelle study.

Minimum prices by oil-producing regions were presented in the Battelle study.

Initial runs of the emissions model indicated that some Battelle prices were not high enough to ration projected production. These prices were raised in iterative fashion as they were for coal until quantity demanded was reduced to levels more consistent with projected production. The resulting price structure is presented in table A.11. Again it is recognized that this approach is a considerable simplification of the market-adjustment process that may actually take place. Yet the procedure does provide a set of prices from which relative prices can be obtained

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*National Coal Association, Steam-Electric Plant Factors, 1971, Washington, D. C., 1972, p. 52.

†MITRE Corp., Survey of Coal Availabilities by Sulfur Content, May 1972.

‡These refining districts correspond with groupings originated by the Petroleum Administration for use during World War II which were called PAW districts. The PAW districts were later changed to PAD (Petroleum Administration for Defense) districts.

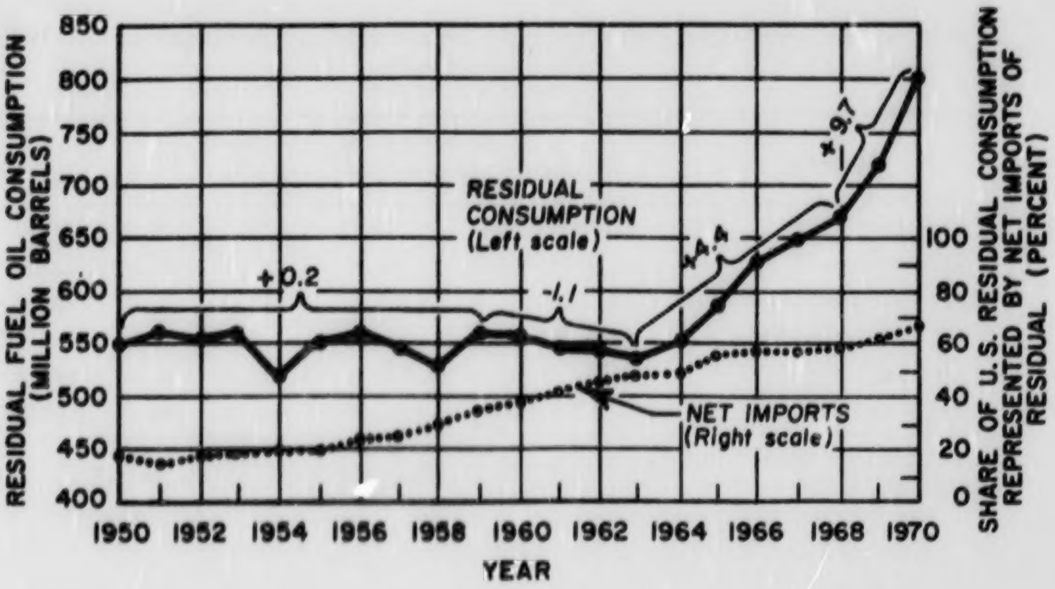

Figure A.5. Residual fuel oil consumption (Source: U.S. Department of the Interior).

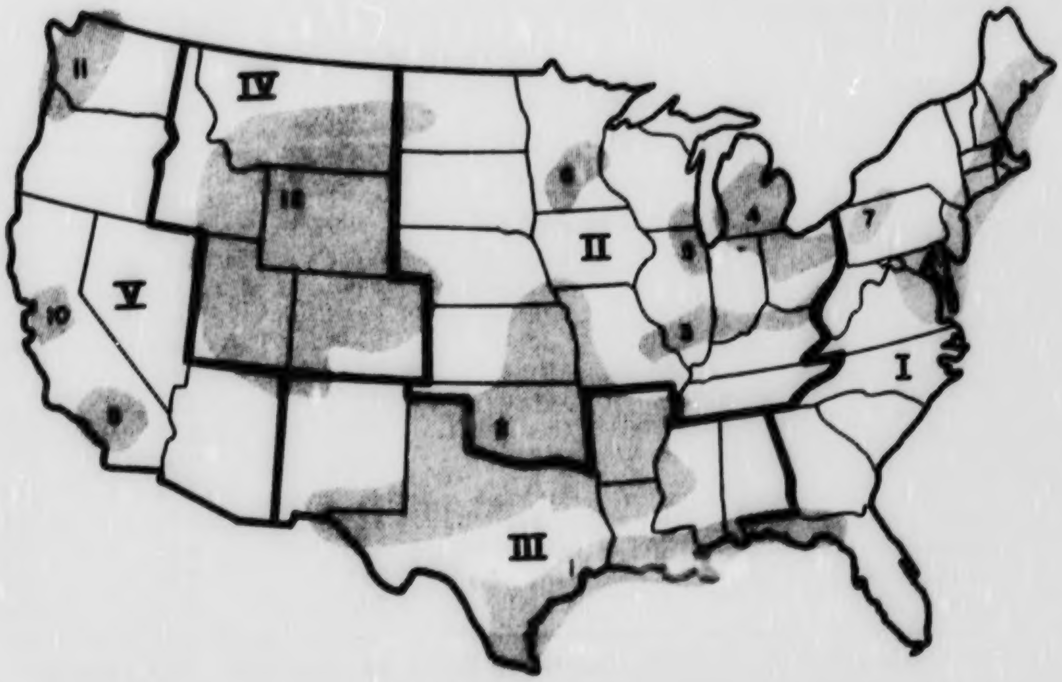
11
IV
12
6
II
5
4
7
10
V
3
9
8
I
III
1

Figure A.6. Oil-producing regions (Source: U.S. Department of the Interior).

Table A.10. Projected maximum U.S. production of residual oils--1978 (billion Btu)

District	Sulfur content (percent) < 0.4	0.4-0.82	0.83-1.65	1.66-2.94	> 2.94	Totals
I: East	8.6	0	0.1	0	0 0	8.7
II: Midwest	121.1	104.0	60.4	31.8	13.9	331.2
III: Southeast-Southwest	854.6	530.8	108.4	207.0	0	1700.8
IV: Rocky Mountain	97.0	16.0	32.9	9.7	34.8	190.4
V: West	39.8	40.1	109.3	121.3	45.2	355.7
Total	1121.1	690.9	311.1	269.8	93.9	2586.8

Source: MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, p. 18.

Table A.11. Oil prices by region (dollars per billion Btu)

Oil region	Sulfur content (percent) 0.4	0.6	1.2	2.3	3.0
1	445	377	338	291	290
2	444	376	350	332	331
3	540	459	399	356	351
4	545	459	410	360	352
5	517	470	435	415	406
6	505	NA	NA	NA	NA
7	517	NA	NA	NA	NA
8	517	NA	NA	NA	NA
9	499	422	375	336	302
10	489	412	375	335	321
11	495	424	378	354	345
12	489	412	365	320	315
Gulf Coast	445	377	338	291	290
Great Lakes	517	470	435	415	406
West Coast	499	422	375	336	302
East Coast	517	490	390	313	266

Source: Adapted from Battelle Memorial Institute, EPA Energy Quality Model, September 1972.

to provide more realistic projections of the cost of control for fuel switching than would a single premium for low sulfur oil.

A.2.2.3 Gas. Gas is an important energy source for steam-electric utilities and the area sources. In addition, gas is also a competitor of electricity, primarily in the commercial and residential heating markets.

No attempt has been made in this study to project the future supply of gas. It has been assumed that sufficient supplies of gas will be available to current users of gas. However, no sources are permitted to switch to gas from coal or oil.

A.2.2.4 Transportation Costs. Transportation costs are an important element in the delivered prices of coal, oil, and gas. In the future, they may assume even larger importance than today since large reserves of low sulfur coal, while available, are located long distances from the population centers where most fuel is consumed. It is necessary, therefore, to incorporate transportation costs into the model that predicts fuel prices to be faced by users.

The transportation matrix developed by Battelle for EPA has been used. This matrix estimates shipping costs from 19 coal-, 12 oil-, and 12 gas-producing regions to each State. The location of each of the nation's steam-electric utilities has been identified in terms of one of these destinations. The transportation costs are approximations of actual costs based on the typical modes used for shipping each fuel, their per mile costs, and distance from origin to destination.

These costs were put on a Btu basis to make them comparable with other fuel costs. The average Btu contents of residual oil and gas used in this study are shown in table A.12.

Table A.12. Oil and gas average Btu contents

Fuel	Average Btu content (millions)	Fuel content
Residual oil	6.287	Per barrel
Gas	1.030	Per million cubic feet

Source: Research Triangle Institute.

The Btu contents of coal vary significantly among origins, especially between the Appalachian and Rocky Mountains. For this reason, it was necessary to adjust the coal transportation costs origin-by-origin. The coal Btu contents are presented in table A.13.

A.2.3 Emissions Reductions and Costs

Cost of control functions for all steam-electric power plants and area sources have been developed based on the costs and effectiveness of the control alternatives costed above, a listing of the nation's utilities which includes relevant parameters for emissions and control cost estimation and State-by-State demands for Btu's by the area sources. These functions are minimum cost functions for achieving sulfur emissions reductions from these two sources.

The long-run industry total and marginal costs of emissions reductions are shown in figures A.7 through A.10. The continuity of these estimated functions is probable, due to the large number of sources and control alternatives.

Table A.13. Coal average Btu contents by origin

Coal-producing region	Average Btu per ton (millions)
1	27
2	27
3	24
4	25
5	28
6	27
7	24
8	23
9	23
10	23
11	27
12	26
13	23
14	19
15	20
16	19
17	21
18	19
19	17

Source: MITRE Corporation, Survey of Coal Availabilities by Sulfur Content, May 1972, pp. II-2 through II-5.

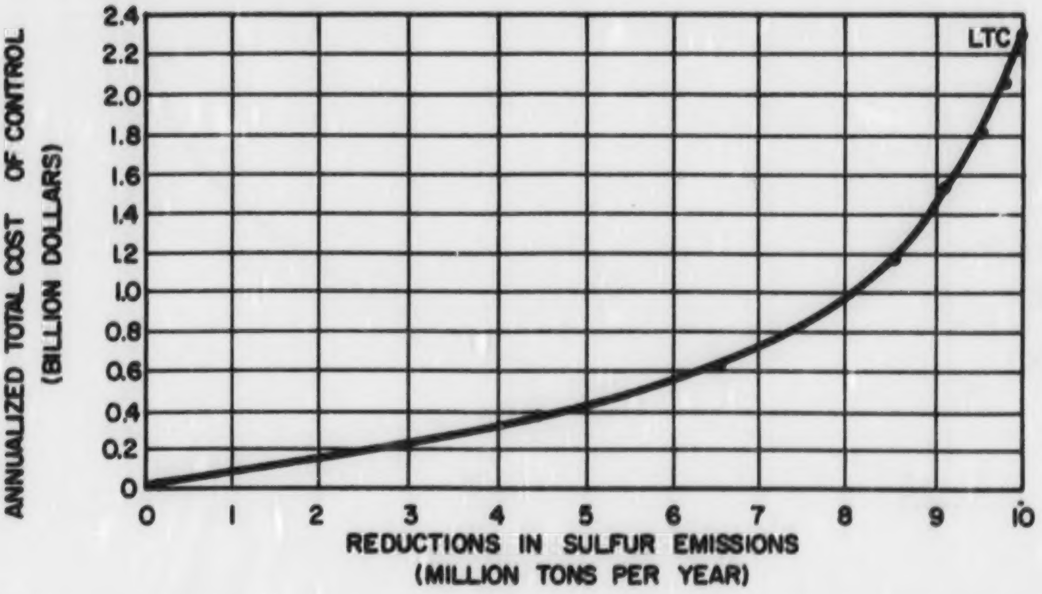

Figure A.7. Total cost* of reductions in sulfur emissions: steam-electric utilities (*does not include emissions tax payments) (Source: Research Triangle Institute).

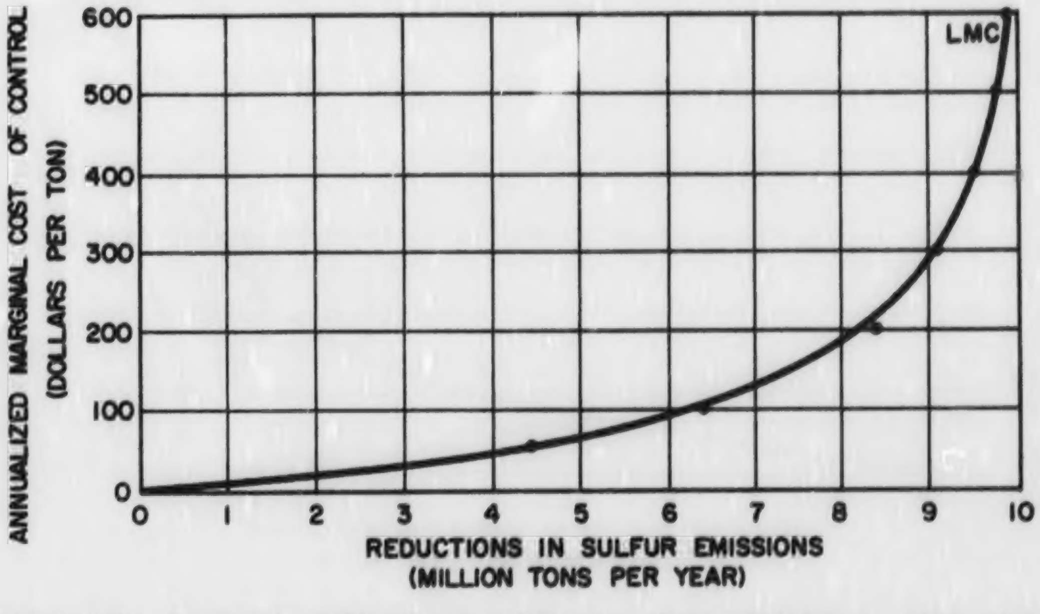

Figure A.8. Marginal cost* of reductions in sulfur emissions: steam-electric utilities (*does not include emissions tax payments) (Source: Research Triangle Institute).

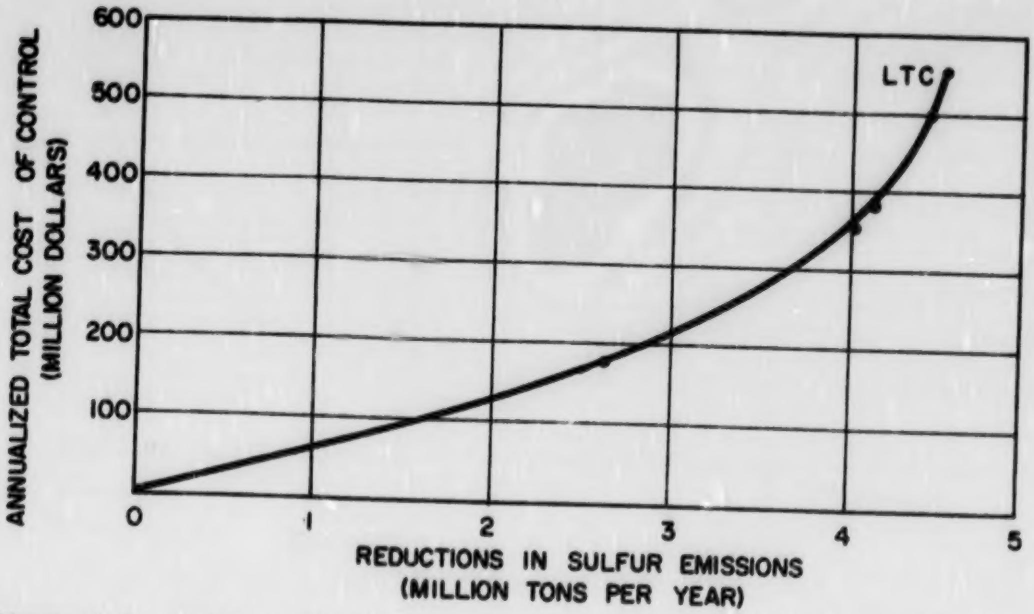

Figure A.9. Total cost* of reductions in sulfur emissions: area sources (*does not include emissions tax payments) (Source: Research Triangle Institute).

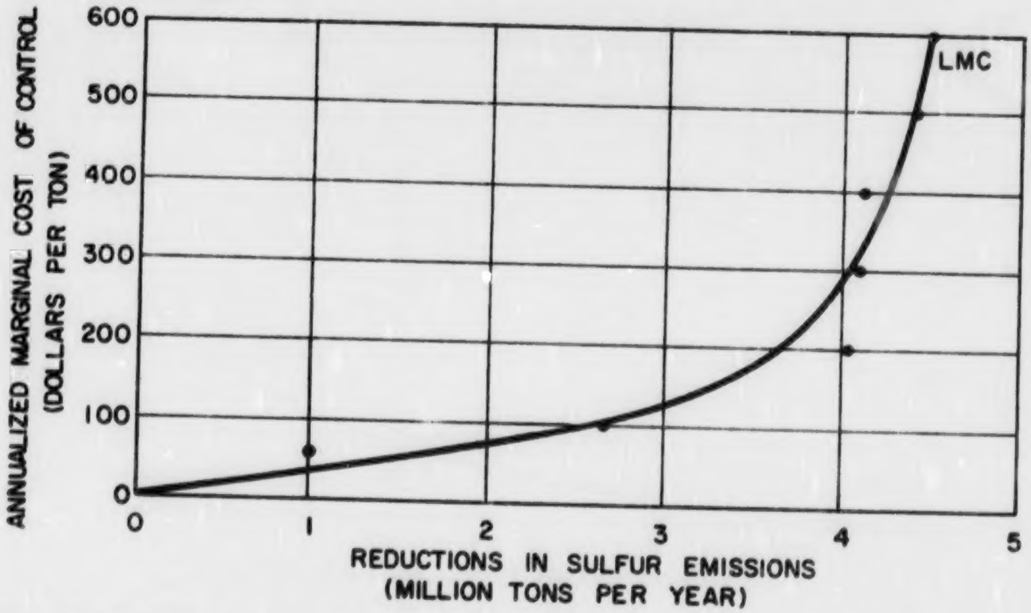

Figure A.10. Marginal cost* of reductions in sulfur emissions: area sources (*does not include emissions tax payments) (Source: Research Triangle Institute).

Appendix B: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR PETROLEUM REFINERIES

This appendix describes the emissions factors used and the control alternatives included and costed as part of this study to project the effect of various sulfur tax rates on petroleum refineries.

B.1 Emission Factors

A variety of processes or operations in a petroleum refinery may produce sulfur dioxide (SO_2) emissions. However, several minor refinery process sources represent only a small (and generally uncertain) fraction of total refinery SO_2 emissions. On the other hand, three major refinery operations produce significant SO_2 emissions and are treated as separate emissions sources: (1) catalyst regenerators, (2) Claus sulfur recovery plants, and (3) fuel combustion processes; i.e., heaters and boilers. As indicated in the estimated 1970 refinery sulfur balance shown in table B.1, the SO_2 emissions from these three operations account for 5.5, 4.5, and 3.3 percent, respectively, (for a combined total of about 13 percent) of the sulfur present in the input crude oil. About 78 percent of the input sulfur is distributed among marketed products (45.9 percent), recovered sulfur (26.7 percent), and waste water effluent (5.7 percent); the remaining 8.4 percent is unaccounted for and represents either SO_2 emissions by other refinery operations for which emission factors are unknown, or the result of using an unrepresentative value for the average sulfur weight percentage of the input crude oil.

B.1.1 Catalyst Regenerators

Catalysts used in catalytic crackers lose some of their activity after extended use and must be either regenerated or replaced. The regeneration process consists of oxidizing coke--which forms on the catalyst during cracking--to carbon monoxide. During regeneration, sulfur and sulfide deposits which also accumulate on the catalyst are oxidized to SO_2. Thus, catalyst regenerators, particularly those associated with Fluid Catalytic Cracker (FCC) units, are a major source of refinery sulfur emissions. As indicated in table B.2, sulfur emission rates from regenerators used with Thermofor Catalytic Cracking (TCC) units are considerably smaller.

Table B.1. Estimated U.S. petroleum refinery sulfur balance--1970

	Barrels (thousand)*	Average sulfur weight (percent)	Sulfur content (thousand tons)		Percent
Input					
Crude oil	3,967,500	0.81†	4,747		100
Disposition					
Products marketed					
Gasoline	2,100,000	0.03	2,178		45.9
Kerosene	96,000	0.05	95		
Jet fuel	302,000	0.3 ††	128		
Distillate oil¶	897,000	0.3 **	408		
Residual oil¶	206,667	1.6 **	533		
Petroleum coke	11,300#	1.8 §	212		
Asphalt	26,500#	3.0 §	795		
Water effluent§	---	---	270		5.7
Sulfur recovered	----	---	1,269		26.7
Refinery emissions§§	---	---	633		13.3
Residual oil burned	43,323	1.8	159	3.3	
Claus plant	---	--	212	4.5	
Fluid catalytic cracker (FCC) regenerators‡	---	---	256	5.4	
Thermofor catalytic cracker (TCC) regenerators‡	---	---	6	0.1	
Total	---	---	4,350		91.6
Unaccounted for	---	---	397		8.4

* Mineral Industry Survey, U.S. Department of Interior, December 23, 1971.

† Estimated average for domestic and imported crude processed in U.S. refineries.

‡ From catalyst coke burning.

§ Estimated.

¶ Excludes imports of 557,000 thousand barrels.

10^3 Ton (coke 5.0 bbl/ton; asphalt 5.5 bbl/ton).

**OAP Data file of Nationwide Emission for 1970, July 1972.

††Domestic airline specification; actual may be lower.

‡‡"Sulfur Content of Crude Oils of the Free World," Bureau of Mines, RI 7059, 1967.

§§Research Triangle Institute.

Table B.2. Sulfur emission factors for petroleum refineries

Emissions source	Sulfur emission factors (lb/thousand barrels of fresh feed or oil burned, as appropriate)
Catalyst regenerators	
Fluid catalytic cracker	262
Thermofor and Houdriflow catalytic cracker	30
Refineries without Claus plants	720
Refineries with Claus plants	72
Fuel combustion	68

Source: Compilation of Air Pollutant Emission Factors, Environmental Protection Agency, Research Triangle Park, N.C., February 1972, pp. 9-1, 9-2.

B.1.2 Claus Plants

Many refinery processes produce off-gases which contain hydrogen sulfide (H_2S). All plants strip the H_2S (usually in excess of 95 percent) from the off-gases before they are burned in process heaters and boilers. If the refinery does not have a Claus plant to convert the stripped H_2S to sulfur, the H_2S stream is flared to the atmosphere and produces large amounts of SO_2. It has been assumed that an average 2-stage Claus plant can provide about a 90-percent conversion of the input H_2S to elemental sulfur, with the remaining unconverted sulfur being emitted as SO_2. An average 4-stage Claus plant is assumed to provide upwards of 95-percent conversion of H_2S. Recently developed "tail gas modifications" of the 4-stage Claus unit provide a 99.9-percent conversion of input H_2S to elemental sulfur.

At present, not all refineries have Claus plants, but those that do generally have 2-stage plants.

B.1.3 Fuel Combustion

Much of the fuel required by refinery process heaters and boilers is produced by the refinery itself. Most of the SO_2 emissions from refinery combustion sources result from the use of liquid fuels such as low value distillate and residual oils. Because of their relatively high sulfur concentrations, these fuels are frequently unsuitable for marketing. As indicated in table B.1, more than 43 million barrels of residual fuel oil were burned in U.S. refineries during 1970. Using an estimated sulfur concentration of 1.8 percent by weight, residual fuel oil combustion in refineries resulted in the release of about 159,000 tons of sulfur to the atmosphere during 1970. Combustion of refinery gases also results in SO_2 emissions; however, these gases are generally scrubbed for removal of sulfur values prior to burning and thus produce relatively little SO_2 in comparison with residual fuel oil combustion.

Sulfur emissions factors for the three refinery sources identified above were derived from the data shown in table B.1, and are shown in table B.2.

B.2 Sulfur Emissions Control Alternatives and Costs

Costs as a function of capacity have been estimated for controlling sulfur emissions from the three emission sources discussed above. In most cases, several techniques for controlling emissions at each source--each technique representing a unique level of control--have been costed. The control cost estimates were based on previous studies for EPA and private communications with EPA personnel. Table B.3 summarizes the alternatives available for controlling sulfur emissions which appear to be most feasible by 1978, and their removal efficiencies by emissions source.

B.2.1 Catalyst Regenerators

Hydrodesulfurization of catalytic cracker feedstock was costed as the most economical technique for reducing sulfur emissions from catalyst regenerators. Catalytic crackers are fed by vacuum gas oil from vacuum distilling units and/or heavy gas oil from atmospheric crude topping units. Hydrodesulfurization processes now in commercial use are effective in removing up to about 95 percent of the sulfur in these oils. Since most of the sulfur present in catalytic cracker feedstock is passed on to the cracked products and only a small fraction is picked up by the catalyst and emitted during catalyst regeneration, both product desulfurization and reduction in regenerator emissions will result from application of this control technique.

Hydrodesulfurization of vacuum gas oil and heavy gas oil involve high-temperature, high-pressure hydrogen treatments in the presence of a catalyst.

Table B.3. Sulfur emission control alternatives for petroleum refineries

Emissions source	Abbreviation*	Alternative	Control alternative	Removal efficiency (percent)
Catalyst regenerator				
FCC	PR-CR	1	Hydrodesulfurization of catalytic cracker feedstock	90
TCC & HCC	PR-CR	2		90
Refineries without Claus plant	PR-S	1	Two-stage Claus plant	90
	PR-S	2	Four-stage Claus plant	95
	PR-S	3	Four-stage Claus plant with tail gas unit	99.5
Refineries with Claus plant	PR-S	4	Add two additional conversion stages to Claus plant	95
	PR-S	5	Add two additional conversion stages to Claus plant plus tail gas unit	99.5
Fuel oil combustion	PR-FC	1	Hydrodesulfurization of residual fuel oil	90

*Abbreviations index to Table B.4.

Source: Research Triangle Institute.

The hydrodesulfurization process generally employs a fixed bed catalytic reactor and a regenerable catalyst. Sulfur compounds are converted to H_2S in the reactor and drawn off with other overhead gases. The H_2S is subsequently separated from the other gases by amine scrubbing and directed to a sulfur plant for conversion to elemental sulfur. The liquid bottoms constitute the desulfurized product which, in this case, will be fed to the catalytic cracker. In addition to sulfur removal, hydrogen treating of catalytic cracker feedstock will reduce coke production in the cracker by 25 to 30 percent and increase gasoline yield. In the present analysis, it was assumed that the hydrodesulfurization process removed 90 percent of sulfur present in the cracker feedstock and effects a similar reduction in sulfur emissions to the atmosphere from the catalyst regenerator.

Annualized costs for several refinery capacities are presented in table B.4 along with emissions data.

Table B.4. Sulfur emission control costs for petroleum refineries

Control alternative by unit process	Control costs (thousand dollars)								Annual emissions after control (tons)				Annual additional recovered sulfur after control (tons)			
	Investment				Annualized total cost of control											
	5,000*	50,000*	100,000*	500,000*	5,000*	50,000*	100,000*	500,000*	5,000*	50,000*	100,000*	500,000*	5,000*	50,000*	100,000*	500,000*
PR-CR(1)	$122	$ 560	$ 900	$2,500	$432	$2,920	$6,200	$24,000	9	84	169	840	532	5,325	10,698	53,250
PR-CR(2)	122	560	900	2,500	432	2,920	6,200	24,000	11	14	29	143	432	5,325	10,698	53,250
PR-S(1)	170	430	600	1,460	23	82	121	421	65	649	1,300	6,495	585	5,846	11,691	58,459
PR-S(2)	180	500	720	1,900	31	108	160	556	32	325	650	3,248	618	6,170	12,341	61,706
PR-S(3)	360	1,000	1,420	3,800	65	227	337	1,168	1	5	13	65	649	6,490	12,978	64,889
PR-S(4)	10	46	120	440	8	26	39	134	32	325	650	3,248	33	324	650	3,247
PR-S(5)	160	380	720	1,950	34	119	177	613	1	5	13	65	64	644	1,287	6,430
PR-FC	30	90	135	375	59	433	806	3,539	6	59	119	594	53	535	1,070	5,346

*Plant capacity, barrels per day.

Source: Developed by Research Triangle Institute for this study from data presented in:

1. Research Triangle Institute, Control Technology for Sulfur Oxide Pollutants, 2nd ed., November 20, 1972.
2. Aalund, L., Hydrodesulfurization Technology Takes on the Sulfur Challenge," Oil and Gas Journal, September 11, 1972, p.79.
3. Berry, B.B., "Reduce Claus Sulfur Emission," Hydrocarbon Processing, April 1972, p. 102.
4. "Characterization of Claus Plant Emissions," Preliminary draft of final report prepared for the Environmental Protection Agency by Process Research, Inc., Cincinnati, Ohio, September 1972.

As shown in the table, a refinery with a capacity of 5,000 bbl/d could reduce fluid catalytic cracker emissions to 9 tons of sulfur annually with an annualized cost of $432,000. The precontrol level is 90 tons annually (i.e., 9 ÷ (1 - removal efficiency of 90 percent)). A refinery would control sulfur emissions from this source when the cost of control plus the tax rate times the remaining emissions was less than the tax times uncontrolled emissions. For this example refinery, this condition would obtain for tax rates in excess of 267 cents per pound of sulfur emissions since:

$$\$432{,}000 + X\ (9) = X\ (90)$$

$$X = \$5{,}333 \text{ per ton or } \$2.67 \text{ per pound}$$

where

X = tax rate per ton of sulfur emissions.

B.2.2 Claus Plants

Annualized costs for Claus plants were prepared for two cases:

(1) In refineries where there is no present Claus plant, there are three possible alternatives: (a) a 2-stage Claus plant, (b) a 4-stage Claus plant, or (c) a 4-stage Claus plant with a tail gas unit.

(2) In refineries where there is an existing 2-stage (assumed) Claus plant, there are 2 possible alternatives: (a) addition

of two additional conversion stages to the existing plant, or (b) the addition of 2 or more conversion stages plus a tail gas unit.

Annualized costs that reflect these alternatives are presented in table B.4 along with emissions data.

B.2.3 Fuel Combustion

Direct desulfurization of residual fuel oil was selected as the most economical technique for controlling sulfur emissions from refinery combustion. Hydrodesulfurization processes applicable to residual fuel oils are similar to those used with vacuum gas oil except that they are more severe and require highly selective, well-designed catalysts which are resistant to metal deposits. Unlike catalysts used in vacuum gas oil hydrodesulfurization, these catalysts normally cannot be regenerated and must be replaced. There are a variety of direct hydrodesulfurization processes used commercially to reduce the sulfur content of marketed residual fuel oils. Sulfur reductions in the 80- to 95-percent range can be achieved by these processes. Despite recent advances, residual fuel oil desulfurization processes are still relatively expensive and are used only when final fuels must be low in sulfur or when the feedstock is of high sulfur content. Because of the high costs involved, desulfurization of residual fuel oil consumed by refineries is not now being practiced.

Residual fuel oil hydrodesulfurization is assumed to remove and recover 90 percent of the sulfur present in the oil, thereby reducing sulfur emissions from refinery residual fuel oil combustion sources to 10 percent of the uncontrolled level. Annualized costs for residual fuel oil desulfurization are presented in table B.4 along with emissions data.

B.2.4 Emissions Reductions and Costs

Industry cost of control functions have been developed based on the costs and effectiveness of the control alternatives costed above and a listing of the nation's petroleum refineries which includes relevant process parameters for emission and control cost estimation. These functions are minimum cost functions for achieving sulfur emissions reductions from the petroleum refining industry. Table B.5 summarizes the refinery data.

The long-run industry total and marginal costs of sulfur emissions reductions are shown in figures B.1 and B.2. The total costs (LTC) increase at an increasing rate throughout the range for which data are available. The marginal costs (LMC) increase with increases in emissions reductions. Beyond reductions of 250,000 tons, the marginal cost function rises quite rapidly.

Table B.5. Size distribution of petroleum refineries (number of refineries)

Capacity (barrels per day) 000	Crude	Catalytic cracking	
		Fluid	Thermofor & Houdriflow
0 - 10	91	16	11
11 - 20	38	33	10
21 - 30	27	23	8
31 - 40	17	14	4
41 - 50	21	10	
51 - 60	11	9	
61 - 70	6	6	
71 - 80	9	4	
81 - 90	13	2	
91 - 100	1	1	
101 - 110	4	2	
111 - 120	3		
121 - 130	1	1	1
131 - 140	5	1	
141 - 150	1	1	
151 - 160	5	2	
161 - 170	3		
171 - 180		2	
181 - 190	2		
191 - 200	5		
201 - 220		1	
221 - 240			
241 - 260	2		
261 - 280			
281 - 300	1		
301 - 325	2		
326 - 350	2		
351 - 375			
376 - 400			
401 - 425			
426 - 450	1		

Source: The Oil and Gas Journal, April 6, 1970, pp. 121-41.

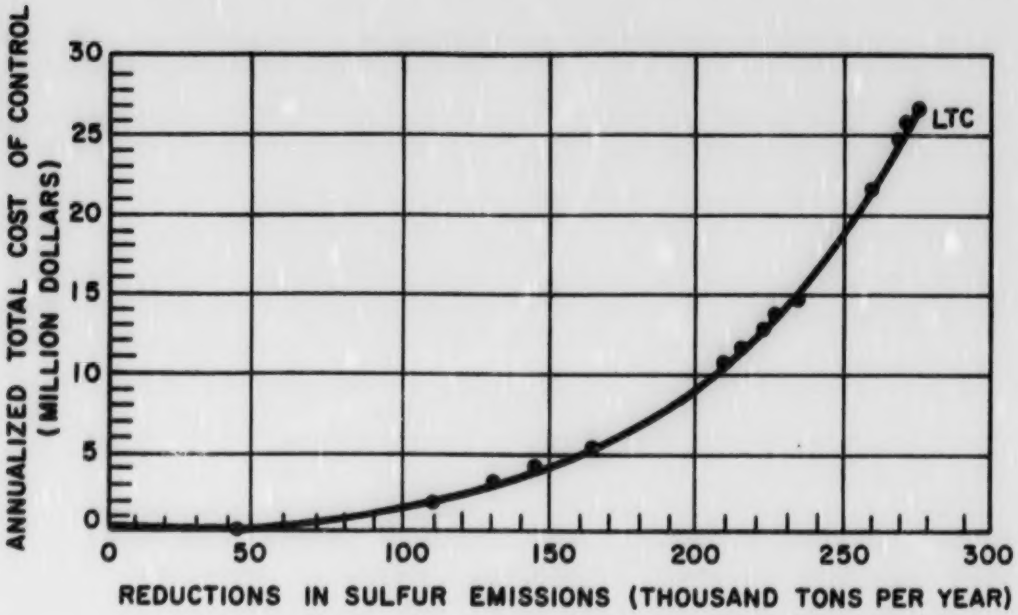

Figure B.1. Total cost* of reductions in sulfur emissions: petroleum refineries--1978 (*does not include emissions tax payments) (Source: Research Triangle Institute).

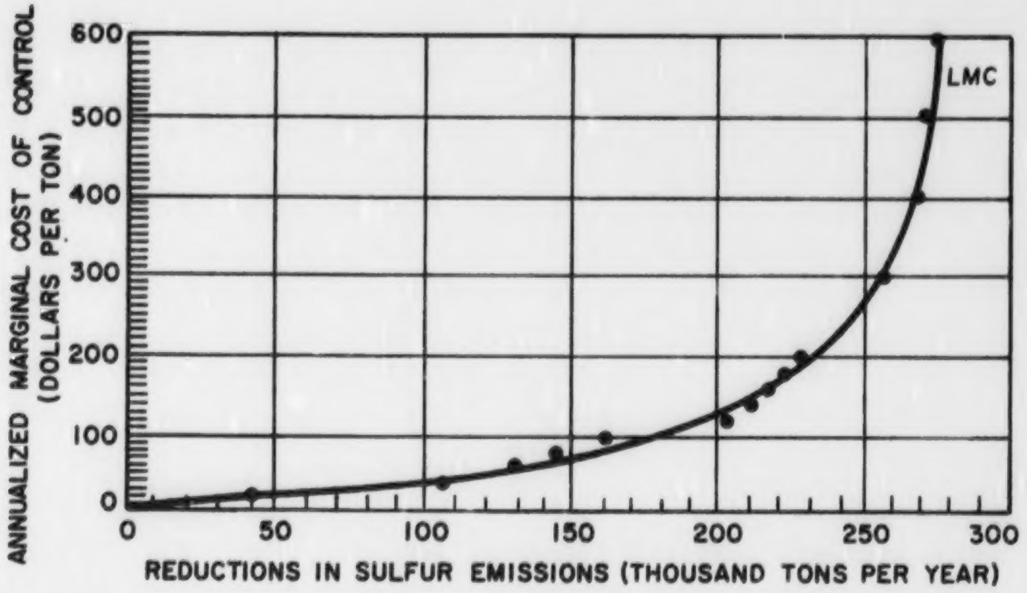

Figure B.2. Marginal cost* of reductions in sulfur emissions: petroleum refineries--1978 (*does not include emissions tax payments) (Source: Research Triangle Institute).

Appendix C: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR SULFURIC ACID PRODUCERS

This appendix describes the emission factors used and the control alternatives included and costed as part of this study to project the effect of various sulfur tax rates on sulfuric acid plants.

C.1 Emission Factors

Sulfur emissions from the production of sulfuric acid by the contact process are of two types. One type is gaseous, as sulfur dioxide (SO_2), which results from the incomplete oxidation of SO_2 to sulfur trioxide (SO_3) in the conversion step. The unconverted SO_2 is not absorbed in the weak sulfuric acid during the absorption step and is emitted in the absorption tower tail gas. The other type of sulfur emission is acid mist which emerges from the absorption tower entrained in the tail gas.

The actual rate of SO_2 emissions from a particular plant depends upon the conversion efficiency of SO_2 to SO_3 and the level of production. For this analysis, a conversion efficiency of 97 percent was used. This results in an emission factor of 40 pounds of SO_2 per ton of 100 percent acid produced.

The quantity of acid mist emissions depends primarily on whether normal sulfuric acid ($\leq$ 99 percent acid) or oleum (100 percent acid plus excess dissolved SO_3) is being produced. For normal sulfuric acid production, an emission factor of 2.5 pounds of acid mist per ton of acid produced was used; while for oleum production, a factor of 7.5 pounds of acid mist per ton of acid production was used.

Fifty percent by weight of SO_2 is sulfur and approximately 32 percent by weight of acid mist is sulfur.

New Source Performance Standards limit SO_2 emissions to a maximum of 4 pounds per ton of acid produced, and limit particulate (acid mist) emissions to a maximum of 0.15 pound per ton of acid produced. The emission factors are summarized in table C.1.

C.2 Sulfur Emissions Control Alternatives and Costs

The control techniques for reducing sulfur emissions from sulfuric acid plants vary depending on whether gaseous or particulate emissions are being controlled. All the systems costed result in the recovery of sulfur in the form of increased sulfuric acid production.

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Table C.1. Sulfur emission factors for sulfuric acid plants

Emissions source	Sulfur emission factors (lb/ton of acid production)
Gaseous	20.00
Mist, normal plants	1.28
Mist, oleum plants	1.28

Source: Compilation of Air Pollutant Emission Factors, U.S. Environmental Protection Agency, Research Triangle Park, N.C., February 1972, pp. 5-18.

Table C.2 summarizes the alternatives available for controlling sulfur emissions and their removal efficiencies by emissions source. These control alternatives represent those that appear most feasible by 1978.

C.2.1 Gaseous Emissions Control

Alternatives for gaseous emissions control have been developed and technically demonstrated: the best are the dual absorption and the sodium sulfite scrubbing techniques. The dual absorption technique requires the interposition of an intermediate absorption tower in the traditional process configuration. By interposing this second absorption tower, overall conversion of SO_2 to SO_3 is increased from 97 to 99.7 percent. Thus, SO_2 emissions are reduced by 90 percent and production of sulfuric acid is increased by nearly 3 percent without additional raw materials.

In the sodium sulfite scrubbing technique, unreacted SO_2 in the exhaust gas is reacted with sodium sulfite to form certain thermally reactive crystals which when heated liberate SO_2. The liberated SO_2 is fed back into the acid plant to increase the yield of the plant by about 3 percent. The control efficiency of this system is about 95 percent.

New sources are expected to meet New Source Performance Standards for gaseous emissions (4 pounds SO_2 per ton of acid) by using dual absorption. The incremental costs necessary for the new sources to use sodium sulfite scrubbing instead of dual absorption are slightly less than those that can

Table C.2. Sulfur emissions control alternatives for sulfuric acid plants

Emissions source	Abbreviation*	Alternative	Control alternative	Removal efficiency (percent)
		EXISTING SOURCES		
Gaseous, all plants	SA-A	1	Dual absorption	90
Gaseous, all plants	SA-A	2	Sodium sulfite scrubbing	95
Mist, normal plants	SA-B	1	Dual mesh pad demister	90
Mist, normal plants	SA-B	2	Tubular fiber demister	99.5
Mist, oleum plants	SA-C	1	Dual mesh pad demister	75
Mist, oleum plants	SA-C	2	Tubular fiber demister	99.5
		NEW SOURCES		
Gaseous, all plants	SAN-A	1	Sodium sulfite scrubbing	60
Mist, normal plants	SAN-B	1	Tubular fiber demister	95

*Abbreviations index to table C.3.

Source: Research Triangle Institute.

be calculated for the existing sources since some economies are achieved in installing these devices on new plants as compared with adding them to existing plants.

C.2.2. Mist Control

Acid mists can be controlled with filter devices called demisters. Two effective demisters are currently available. These are the dual mesh pad demister and the tubular fiber demister which achieve control efficiencies of 90 and 99.5 percent, respectively, in nonoleum plants; the corresponding control efficiencies for oleum plants are 75 and 99.5 percent.

New sources are expected to meet the New Source Performance Standards for mist emissions (0.15 pound of mist per ton of acid) by dual mesh pad demisters in the normal acid plant and tubular fiber demisters in the oleum plants. The control alternatives, their costs, and effectiveness in controlling SO_2 emissions from sulfuric acid production were derived from several studies for EPA as well as private communications with EPA personnel. These costs have been estimated on an annualized basis for representative plant sizes (table C.3). Interpolation is used to derive cost estimates for plant sizes other than those estimated for the representative plant sizes.

As shown in table C.3 for an annualized cost of \$67,000, emissions from a 50-ton-per-day plant can be reduced to 19 tons of sulfur annually. The pre-control level is 190 tons annually (i.e., 19 ÷ (1 - removal efficiency of 90 percent)). A plant would control sulfur emissions using dual absorption when the cost of control plus the tax rate times the remaining emissions was less than the tax times uncontrolled emissions. For this example plant, that would be for tax rates greater than 20 cents per pound of sulfur emissions since:

$$\$67{,}000 + X\ (19) = X\ (190)$$

$$X = \$391 \text{ per ton or 20 cents per pound}$$

where

X = tax rate per ton of sulfur emissions.

C.2.3. Emissions Reductions and Costs

Industry cost of control functions have been developed based on the costs and effectiveness of the control alternatives costed above and a listing of the nation's sulfuric acid plants using the contact process. This listing includes relevant plant information for emissions and cost estimation; the size and type distribution is shown in table C.4. The functions are minimum cost functions for achieving sulfur emissions reductions from the sulfuric acid industry.

The long-run industry total and marginal costs of sulfur emissions reductions are shown in figures C.1 and C.2. The total costs (LTC) increase at a moderately increasing rate until the higher levels of emissions reductions are reached. This is reflected in the marginal cost curve (LMC) which rises rapidly after reductions of about 285,000 tons are achieved.

Table C.3. Sulfur emissions control costs for sulfuric acid

Control alternative by unit process	Control costs (thousand dollars)								Annual emissions after control (tons)				Annual additional recovered sulfur after control† (tons)			
	Investment				Annualized											
	50*	250*	750*	1500*	50*	250*	750*	1500*	50*	250*	750*	1500*	50*	250*	750*	1500*
							EXISTING SOURCES									
SA-A(1)	$242	$636	$1,230	$1,864	$67	$186	$383	$612	19	94	281	563	169	844	2,531	5,063
SA-A(2)	295	776	1,500	2,273	88	259	563	937	9	47	141	281	178	891	2,672	5,344
SA-B(1)	16	40	105	194	5	13	35	64	0.8	3.8	11.5	23.0	6.9	34.5	103.3	206.6
SA-B(2)	43	114	245	396	12	33	74	124	0.0	0.2	0.6	1.1	7.7	38.1	114.2	228.5
SA-C(1)	16	40	105	194	5	13	35	64	5.7	28.7	86.1	172.7	17.3	86.1	258.3	516.1
SA-C(2)	43	114	245	396	12	33	74	124	0.8	3.8	111.5	23.0	22.2	110.0	332.9	665.8
							NEW SOURCES									
SAN-A(1)	272	751	1,500	2,321	21	73	180	325	9	47	141	281	9	47	141	281
SAN-B(1)	23	62	105	140	7	20	39	60	0.0	0.2	0.6	1.1	1	3.6	10.9	21.9

*Plant size in tons of sulfuric acid processed per day.

†Sulfur equivalent of sulfuric acid.

Source: Developed by Research Triangle Institute from data presented in:

1. Background Information for Proposed New Source Performance Standards, APTD-0711, Environmental Protection Agency, August 1971.
2. Chemico Construction Corporation, Engineering Analysis of Emissions Control Technology for Sulfuric Acid Manufacturing Processes, NAPCA, March 1970 (NTIS No. PB-190 393).
3. Boys, Paul A., Environmental Protection Agency (private communication), November 1972.
4. Buckhardt, D.B., VonBrae, Inc. (private communication), October 1972.
5. Walsh, R., Environmental Protection Agency (private communication), September 1972.
6. Carey, D., Environmental Protection Agency (private communication), September 1972.

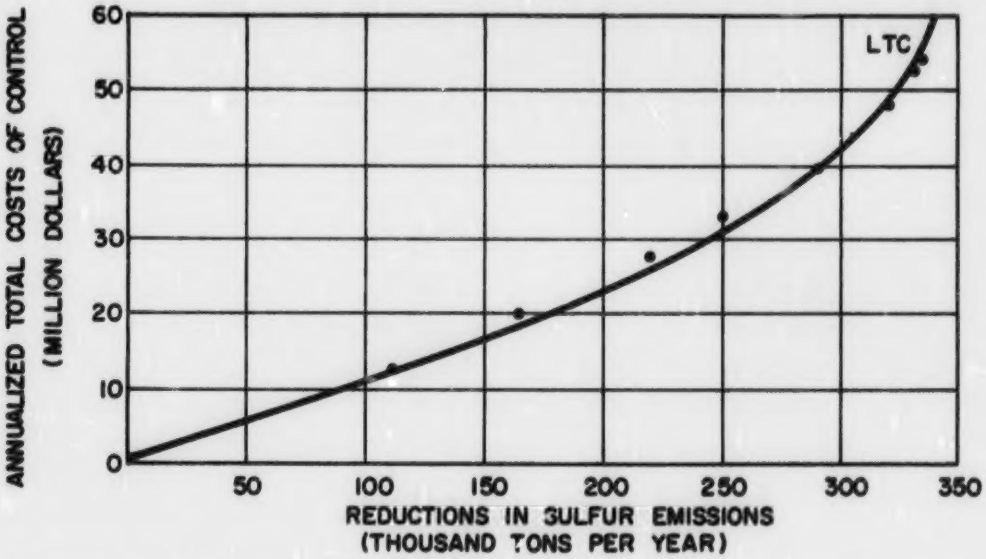

Figure C.1. Total cost* of reductions in sulfur emissions: sulfuric acid producers (*does not include emissions tax payments) (Source: Research Triangle Institute).

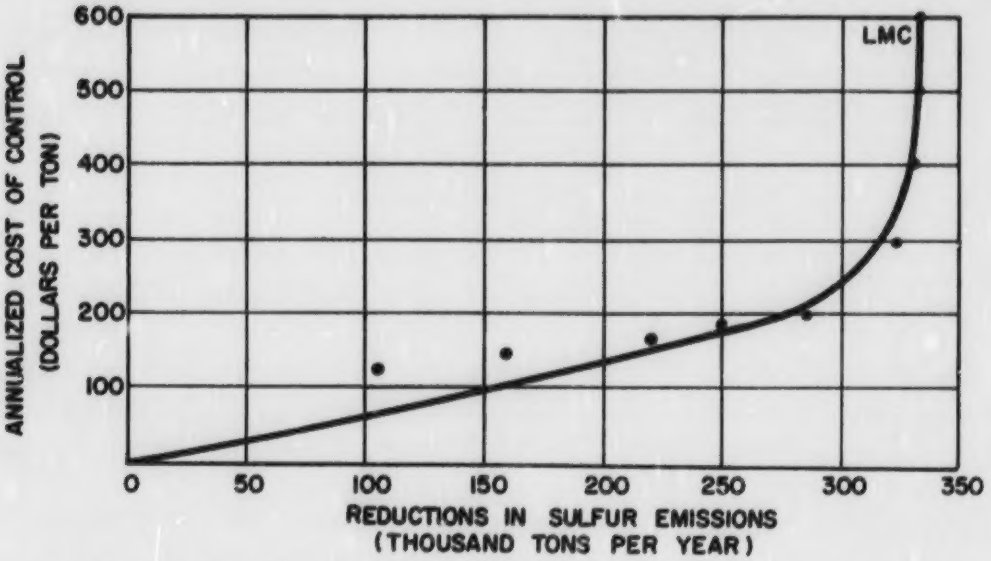

Figure C.2. Marginal cost* of reductions in sulfur emissions: sulfuric acid producers--1978 (*does not include emissions tax payments) (Source: Research Triangle Institute).

Table C.4. Size distribution of sulfuric acid plants

Capacity*	Normal Plants	Oleum Plants
less than 100	16	2
100-199	24	9
200-299	18	10
300-399	12	6
400-499	14	7
500-749	21	10
750-999	14	6
1,000-1,499	5	2
1,500 & over	28	4

*Plant size in tons of sulfuric acid processed per day.

Source: Research Triangle Institute.

Appendix D: SULFUR EMISSION FACTORS AND CONTROL COSTS FOR PRIMARY NONFERROUS SMELTERS

This appendix discusses the emission factors used, and the control alternatives included and costed as part of this study to project the effect of various sulfur tax rates on primary nonferrous smelters.

D.1 Emission Factors

D.1.1 Copper Smelters

The three principal sources of sulfur dioxide (SO_2) emissions from copper smelters are roasters, reverberatory furnaces, and converters. Total emissions from all these sources amount to approximately 1,250 pounds of SO_2 for every ton of ore concentrate charged. Of the 15 operating smelters, 7 do not use a roaster but instead charge the reverberatory furnace directly with the ore concentrate. The roaster, where used, produces about 40 percent of total SO_2 emissions; the reverberatory furnace, 20 percent; and lastly the converter, 40 percent. If no roaster is used, the reverberatory furnace produces about 30 percent of the total emitted and the converter the remaining 70 percent. Sulfur emission factors are shown in table D.1.

Table D.1. Sulfur emission factors for copper smelters

Emissions source	Emission factor (pounds of sulfur per ton of ore concentrate)
Roaster	249
Reverberatory furnace (w/o roaster)	186
Reverberatory furnace (w/roaster)	125
Converter (w/o roaster)	435
Converter (w/roaster)	249

Source: Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Primary Copper Industry, September 1962.

Table D.2. Sulfur emission factors for zinc smelters

Emissions source	Emission factor (pounds of sulfur per ton of ore concentrate)
Roaster (dead roast)	600.0
Sinterer (after roast)	Negligible
Sinterer (no roast)	630.0
Reduction	Negligible

Source: Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Zinc Industry, April 1971.

D.1.2 Zinc Smelters

Totally uncontrolled emissions from zinc smelters amount to about 1,100 pounds of SO_2 per ton of ore charged. Where roasting takes place, either alone or in conjunction with sintering, it accounts for virtually 100 percent of the SO_2 emitted. Where the zinc concentrate is processed solely in a sintering machine (actually it is a combination roaster-sinterer), this unit process produces 100 percent of all SO_2 emitted in the smelting operation. Table D.2 presents sulfur emission factors for zinc smelters.

D.1.3 Lead Smelting

Totally uncontrolled emissions from lead smelters amount to about 660 pounds of SO_2 per ton of ore charged. Roughly 98 percent of this total is emitted in the sintering step, with the remaining 2 percent emitted from blast furnaces. Table D.3 presents emission factors for lead smelters.

D.2 Sulfur Emissions Control Alternatives and Costs

The SO_2 control methods that are likely to be employed in the near future are:

(a) sulfuric acid plants,
(b) lime and limestone scrubbing,
(c) amine absorption,
(d) ammonia scrubbing, and
(e) sodium sulfite-bisulfite absorption.

The best choice of a control technique from the standpoint of well-developed technology is the sulfuric acid plant. However, it requires that the concentration of SO_2 in the feed gas be at least 3.5 percent for a single

Table D.3. Sulfur emission factors for lead smelters

Emissions Source	Emission factor (pounds of sulfur per ton of concentrate)
Roaster-sinterer	472
Blast furnace or dross reverberatory furnace	58

Source: Compilation of Air Pollutant Emission Factors, U.S. Environmental Protection Agency, pp. 7-8.

contact plant and 5 percent for a double contact plant. Unfortunately, some tail gas streams, notably those from reverberatory furnaces, are normally below these minimum concentrations. For this reason, two methods that can be used on dilute streams are considered in this analysis. One is limestone scrubbing, which has an 85 to 90 percent efficiency and a throwaway byproduct; the other is amine scrubbing, which can achieve 99 percent efficiency and produces concentrated SO_2 which may either be sold as is or mixed with lean tail gas streams to enrich the input stream to a sulfuric acid plant. Control cost estimates were based chiefly on previous studies for EPA and private communications with EPA personnel.

In certain instances, process modification or replacement was incorporated into the design of control alternatives. The purpose, where this alternative was chosen, was to produce waste gas richer in SO_2 and more amenable to the application of control techniques that produce a marketable byproduct.

The control alternatives costed represent those that appear most feasible by 1978. Other alternatives may develop in response to the demand for more cost-effective methods of smelter sulfur emissions control as a result of an emissions tax. Those alternatives, of course, could not be included in the analysis.

D.2.1 Copper Smelters

As stated above, gas streams with an SO_2 concentration of less than 3.5 percent are not amenable to direct input into a sulfuric acid plant.

Available data indicate that roaster off-gases average about 8 percent SO_2, reverberatory furnaces 1 to 2 percent, and converters about 7 percent.

Where a tail gas stream of SO_2 concentration less than 3.5 percent exists, there are essentially two control alternatives. One is to concentrate the SO_2 and then input this into an acid plant. The other is to scrub the lean gas and forego the recovery of economically valuable sulfur products.

The alternative costed to provide a method for concentrating SO_2 is amine absorption. In this technique, the low SO_2 concentration gas stream is passed through an absorption bed on which up to 99 percent of the SO_2 is absorbed. This bed can then be stripped, yielding an almost pure stream of SO_2. This SO_2 can be fed into an acid plant either alone or in combination with off-gases from other smelting until processed.

The alternative costed to scrub the weak SO_2 stream is wet limestone scrubbing. In this system, the gas stream is passed through a wet limestone slurry, the end product of which is solid calcium sulfate ($CaSO_4$) which must be disposed of, there being no commercial use available. An SO_2 removal efficiency of 90 percent may be expected from the application of wet limestone scrubbing.

Where a sufficiently concentrated gas stream was available, a sulfuric acid plant was costed as the control alternative. It must be remembered, however, that a sulfuric acid plant does not provide 100 percent control of the input SO_2. For the purposes of this analysis, it was assumed that a single-absorption sulfuric acid plant will emit approximately 2,000 parts per million (ppm) SO_2 in its off-gas stream; while a double-absorption plant will emit about 500 ppm SO_2. Table D.4 indicates the expected removal efficiencies of single- and double- absorption systems as a function of the input SO_2 concentrations. Double absorption can reduce SO_2 emissions below those effected by single absorption, but, of course, at a significantly higher cost.

Three additional control alternatives are possible. Two alternatives are the installation of either (a) single- or (b) double-absorption acid plants where none now exist; the third alternative is the addition of a dual absorption capability to an existing single-absorption plant.

For the purposes of this analysis, the 15 existing copper smelters are characterized by two parameters. These are: (1) the unit processes employed and (2) the presence or absence of an acid plant (it should be noted that all

Table D.4. Sulfur dioxide removal efficiencies of sulfuric acid plants as a function of input concentrations for single- and double-absorption systems

Input SO_2 concentration percent	Removal efficiency (percent)	
	Single absorption	Double absorption
3.5	94.3	98.6
5.0	96.0	99.0
7.5	97.4	99.3
10.0	98.0	99.5

Source: Research Triangle Institute.

existing smelter acid plants are of the single contact variety and that no smelters practice limestone scrubbing). Thus, a copper smelter can have "green feed" to the reverberatory furnace (i.e., no roaster) plus converters, or it can have "conventional feed" (i.e., ore concentration to a preliminary roaster) plus reverberatory furnaces and converters; for each of these plant types, there may or may not be an existing acid plant. These four plant types are summarized in table D.5 along with an abbreviation for each type which will be used in subsequent discussion. Each copper smelter in the plant inventory has been identified as being one of the four plant types.

Table D.5. Copper smelter plant types

Plant type	Abbreviated designation
Green feed (no acid plant)	Cu-A
Green feed (acid)	Cu-B
Conventional feed (no acid plant)	Cu-C
Conventional feed (acid plant (on roaster or converters))	Cu-D

Source: Research Triangle Institute.

Table D.6. Sulfur emission control alternatives for copper smelters

Plant type	Alternative	Control alternative	Removal efficiency (percent)
Cu-A	1	Double-absorption acid plant on converters	68.6
	2	Double-absorption acid plant on converters & limestone scrubbing on reverberatory furnace	95.6
	3	Double-absorption acid plant on converters & amine absorption on reverberatory furnace (concentrated SO_2 to double-absorption acid plant)	97.5
Cu-B	1	Limestone scrubber on reverberatory furnace	95.3
	2	Amine absorption on reverberatory furnace (concentrated SO_2 to an acid plant)	97.2
Cu-C	1	Double absorption on converter & roaster	78.6
	2	Double absorption on converter, roaster, and reverberatory furnace (amine absorber concentrates the reverberatory furnace flow)	98.2
Cu-D	1	Double-absorption acid plant on either roaster or converters	78.2
	2	Double-absorption acid plant on either roaster or converter & amine absorber on reverberatory furnace (concentrated SO_2 stream to new double-absorption plant)	97.9

Source: Research Triangle Institute.

Sets of SO_2 control alternatives were selected independently for each plant type. These alternatives are listed in summary fashion in table D.6.

Table D.7 presents a summary of the costs and emissions associated with each control alternative for selective plant sizes.

D.2.2 Zinc Smelters

Zinc smelters can be categorized into three plant types:

(a) Combination roaster-sintering machine (downdraft type)--no acid plant,

Table D.7. Sulfur emission control costs for copper smelters

Control alternative by unit process	Control costs (million dollars)						Annual emissions after control (thousand tons)			Annual additional recovered sulfur after control† (thousand tons)		
	Investment			Annualized								
	100*	200*	600*	100*	200*	600*	100*	200*	600*	100*	200*	600*
Cu-A(1)	$ 6.3	$ 9.8	$19.6	1.37	2.17	4.30	13.3	26.5	79.5	29.0	58.1	174.2
Cu-A(2)	9.2	14.3	28.6	2.52	4.01	7.00	1.8	3.7	11.0	29.0	58.1	174.2
Cu-A(3)	13.8	21.4	42.8	3.00	4.75	9.37	1.1	2.1	6.3	41.3	82.5	247.5
Cu-B(1)	2.9	4.5	9.0	1.15	1.84	3.67	2.0	4.0	12.1	0	0	0
Cu-B(2)	10.0	15.5	31.0	2.13	3.38	6.75	1.2	2.4	7.3	12.4	24.9	74.7
Cu-C(1)	7.2	11.2	22.4	1.52	2.41	4.81	9.1	18.1	54.5	33.2	66.4	199.1
Cu-C(2)	15.3	23.7	47.4	3.15	4.99	9.96	0.7	1.5	4.4	41.5	83.0	249.1
Cu-D(1)	4.5	7.0	14.0	0.96	1.53	3.05	9.2	18.4	55.2	33.0	66.0	198.0
Cu-D(2)	13.2	20.5	41.0	2.65	4.19	8.37	0.9	1.8	5.5	41.3	82.5	247.5

*Plant size in tons of copper processed per day.

†Sulfur equivalent of sulfuric acid.

Source: Research Triangle Institute.

Arthur G. McKee and Co., Systems Study for Control of Emissions, Primary Nonferrous Smelting Industry, VII, Final report to National Air Pollution Control Administration, Contract PH86-65-85, June 1969.

Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Primary Copper Industry, September 1962.

Fluor Utah Engineers and Contractors, The Impact of Air Pollution Abatement on the Copper Industry, April 1971.

Kennecott Copper Corporation, Copper Smelting Current Practices and Future Developments, AIME Annual Meeting, February-March 1971.

(b) Roaster(s) followed by the sintering machine(s) with the acid plant(s) receiving tail gas from the roaster(s),

(c) Roaster(s) followed by electrolytic purification with the acid plant(s) receiving the tail gas from the roaster(s).

For the purpose of this analysis, these three plant types were termed Zn-A, Zn-B, and Zn-C, respectively. Each zinc smelter in the plant inventory has been identified as being one of the three plant types. The combination roaster-sinterer emits a tail gas stream with an SO_2 concentration of 2 to 2.5 percent. This concentration is too low to be used as input to a sulfuric acid plant. In plants with a separate roaster and sintering machine, the roaster accounts for practically 100 percent of the SO_2 emitted. However, not all roasters can be controlled with acid plants. Older Ropp-type roasters issue a gas stream with an SO_2 concentration less than 1 percent. There is, however, only one plant that presently employs Ropp-type roasters and this plant is expected to close by 1975; it has not been included in this analysis. All other roasters can be and are presently controlled by single contact sulfuric acid plants.

Control alternatives for the roaster-sintering machine included replacing the downdraft machine with an updraft machine which emits two off-gas streams One stream, which contains about 85 percent of all the sulfur emitted, has an SO_2 concentration. The rich gas stream is amenable to control by an acid plant. The other alternative is to replace the existing downdraft machine with a recirculating updraft machine with a single off-gas stream having an SO_2 concentration of about 5 percent. This single stream may then be input into an acid plant.

In plants with a roaster and an acid plant, there are two alternatives. One is to convert the single contact plant to a double contact plant thus increasing the conversion of $SO_2 + SO_3$. The other alternative is to add a Wellman Scrubber to treat the tail gas of the acid plant. The Wellman process not only scrubs the SO_2 out of the acid plant tail gas, but also upon regeneration yields a high SO_2 concentration stream which can be used as input to the acid plant; thus, like the double contact process, the Wellman process increases the effective yield of the acid-making process. These alternatives are summarized in table D.8. Table D.9 summarizes the

Table D.8. Sulfur emission control alternatives for zinc smelters

Plant type	Alternative	Description	Removal efficiency (percent)
Zn-A	1	Convert to updraft sintering and place acid plant on rich stream from sinter.	85.3
	2	Convert sintering machine to recirculating updraft sintering with acid on entire off-gas stream.	96.0
Zn-B	1	Add double contact to present acid plant.	99.0
	2	Add Wellman Scrubber to present acid plant.	99.5
Zn-C	1	Add double contact to present acid plant.	99.7
	2	Add Wellman Scrubber to present acid plant.	99.9

Source: Research Triangle Institute.

Table D.9. Sulfur emission control costs for zinc smelters

Control alternative by unit process	Control costs (million dollars)						Annual emissions after control (tons)			Annual additional recovered sulfur after control† (tons)		
	Investment			Annualized								
	100*	350*	600*	100*	350*	600*	100*	350*	600*	100*	350*	600*
Zn-A(1)	$3.9	$ 8.6	$12.1	$0.548	$1.300	$1.890	2,772	9,669	16,566	15,048	52,701	90,354
Zn-A(2)	5.3	11.7	16.4	0.717	1.702	2.468	759	2,460	4,521	17,259	60,390	103,521
Zn-B(1)	0.262	0.556	0.768	0.073	0.160	0.225	129	455	779	436	1,525	2,614
Zn-B(2)	0.320	0.679	0.938	0.095	0.226	0.328	96	337	574	469	1,643	2,812
Zn-C(1)	0.262	0.556	0.768	0.073	0.160	0.225	50	172	294	442	1,544	2,647
Zn-C(2)	0.320	0.679	0.938	0.095	0.226	0.328	23	86	149	465	1,630	2,795

*Plant size in tons of zinc processed per day.

†Sulfur equivalent of sulfuric acid.

Source: Research Triangle Institute.

Arthur G. McKee and Co., Systems Study for Control of Emissions, Primary Nonferrous Smelting Industry, VII, Final report to National Air Pollution Control Administration, Contract PH86-65-85, June 1969.

Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Primary Zinc Industry, September 1962.

costs and emissions associated with each control alternative for selected plant sizes.

D.2.3. Lead Smelters

Lead smelters can be categorized into three plant types:

(a) Plants with downdraft sintering machines and no acid plant,
(b) Plants with updraft sintering machines and no acid plant,
(c) Plants with updraft sintering machines with an acid plant on the strong (high SO_2 concentration) off-gas stream only.

These plant types have been given the abbreviated designations Pb-A, Pb-B, and Pb-C, respectively. Each lead smelter in the plant inventory has been identified as being one of the three plant types.

The downdraft machines emit an off-gas stream with an SO_2 concentration too low to be used as input into an acid plant. Updraft machines emit two gas streams: one, the so-called rich gas stream, is amenable to control by an acid plant; the lean gas stream is not. The alternatives selected for this study are summarized in table D.10.

D.2.4 Emissions Reductions and Costs.

Industry cost of control functions have been developed based on the costs and effectiveness of the control alternatives costed above and a listing of the nation's smelters which includes relevant process parameters for emissions and control cost estimation. The smelter size distribution is

Table D.10. Sulfur emission control alternatives for lead smelters

Plant type	Alternative	Description	Removal efficiency (percent)
Pb-A	1	Downdraft machine replaced with an updraft type and acid plant installed on rich SO_2 stream.	84.6
	2	Updraft machine of recirculating type with an acid plant on combined sinter off gas.	94.9
	3	Updraft sintering machine and acid plant on rich stream and limestone scrubber on lean stream.	96.3
Pb-B	1	Acid plant on rich stream.	84.6
	2	Weak sinter gas, recirculated and acid plant on combined off gas.	94.9
	3	Acid plant on rich stream and limestone scrubber on lean stream.	96.3
Pb-C	1	Limestone scrubber on lean stream.	96.3

Source: Research Triangle Institute.

Table D.11. Sulfur emission control costs for lead smelters

Control alternative by unit process	Control costs (million dollars)						Annual emissions after control (tons)			Annual recovered sulfur after control† (tons)		
	Investment			Annualized								
	100*	350*	600*	100*	350*	600*	100*	350*	600*	100*	350*	600*
Pb-A(1)	$2.760	$6.080	$ 8.540	$0.589	$1.517	$1.829	1,274	4,455	7,623	6,996	24,486	41,976
Pb-A(2)	3.650	8.040	11.290	0.626	1.596	1.939	426	1,485	2,544	7,821	27,423	47,025
Pb-A(3)	3.750	8.260	11.590	1.012	2.446	3.129	317	1,069	1,832	6,996	24,486	41,976
Pb-B(1)	1.180	2.600	3.650	0.431	0.951	1.340	1,274	4,455	7,623	6,996	24,486	41,976
Pb-B(2)	2.070	4.560	6.400	0.468	1.030	1.450	426	1,485	2,544	7,821	27,423	47,025
Pb-B(3)	2.170	4.780	6.710	0.854	1.880	2.640	317	1,069	1,832	6,996	24,486	41,976
Pb-C(1)	0.990	2.180	3.060	0.421	0.928	1.300	317	1,069	1,832	0	0	0

*Plant size in tons of lead processed per day.

†Sulfur equivalent of sulfuric acid.

Source: Research Triangle Institute.

Arthur G. McKee and Co., Systems Study for Control of Emissions, Primary Nonferrous Smelting Industry, VII, Final report to National Air Pollution Control Administration, Contract PH86-65-85, June, 1969.

Arthur D. Little, Inc., Economic Impact of Anticipated Pollution Abatement Costs on the Primary Lead Industry, September 1962.

shown in tables D.12 through D.14. These functions are minimum cost functions for achieving sulfur emissions reductions from the primary nonferrous smelting industries.

Using lead smelters as an example, a 100 ton per day, type A smelter can reduce emissions to 1,274 tons annually for an annualized cost of \$589,000 (table D.11). The precontrol level of emissions is 8,273 tons of sulfur annually (i.e., 1,274 ÷ (1 - removal efficiency of 84.6 percent)). A smelter would control sulfur emissions by installing an acid plant where the cost of control plus the tax rate times the remaining emissions was less than the tax times the uncontrolled emissions. For this example smelter, that would be for tax rates greater than 4 cents per pound of sulfur emissions since:

$$\$589{,}000 + \text{TAX}\,(1{,}274) = \text{TAX}\,(8{,}273)$$

$$\text{TAX} = \$84 \text{ per ton or 4 cents per pound}$$

where

X = tax rate per ton of sulfur emitted.

The long-run industry total and marginal unit costs of emissions reductions are shown in figures D.1 and D.2. Because of the absence of technology that could provide intermediate levels of control at acceptable costs and the limited number of plants, the total cost function (LTC) is probably discontinuous throughout all but the upper ranges. The marginal costs (LMC) rise slowly until emissions reductions of about 94 percent (1.5 million tons) are reached. After that point, marginal costs rise quite sharply.

Table D.12. Size distribution of copper smelters

Capacity*	Plant type			
	Cu-A	Cu-B	Cu-C	Cu-D
0 - 99	-	-	-	1
100 - 199	-	-	-	-
200 - 299	4	-	-	2
300 - 399	2	-	1	1
400 - 499	-	-	-	1
500 - 599	-	-	-	2
700 - 799	-	1	-	-

*Plant size in tons of copper processed per day.

Source: Research Triangle Institute.

Table D.13. Size distribution of zinc smelters

Capacity*	Plant type		
	Zn-A	Zn-B	Zn-C
100 - 199	-	1	1
200 - 299	1	-	1
300 - 399	-	-	1
400 - 499	-	1	-
500 - 599	-	1	-

*Plant size in tons of zinc processed per day.

Source: Research Triangle Institute.

Table D.14. Size distribution of lead smelters

Capacity*	Plant type		
	Pb-A	Pb-B	Pb-C
100 - 199	1	1	-
200 - 299	-	1	-
300 - 399	-	-	1
400 - 499	-	-	1
800 - 899	-	-	1

*Plant size in tons of lead processed per day.

Source: Research Triangle Institute.

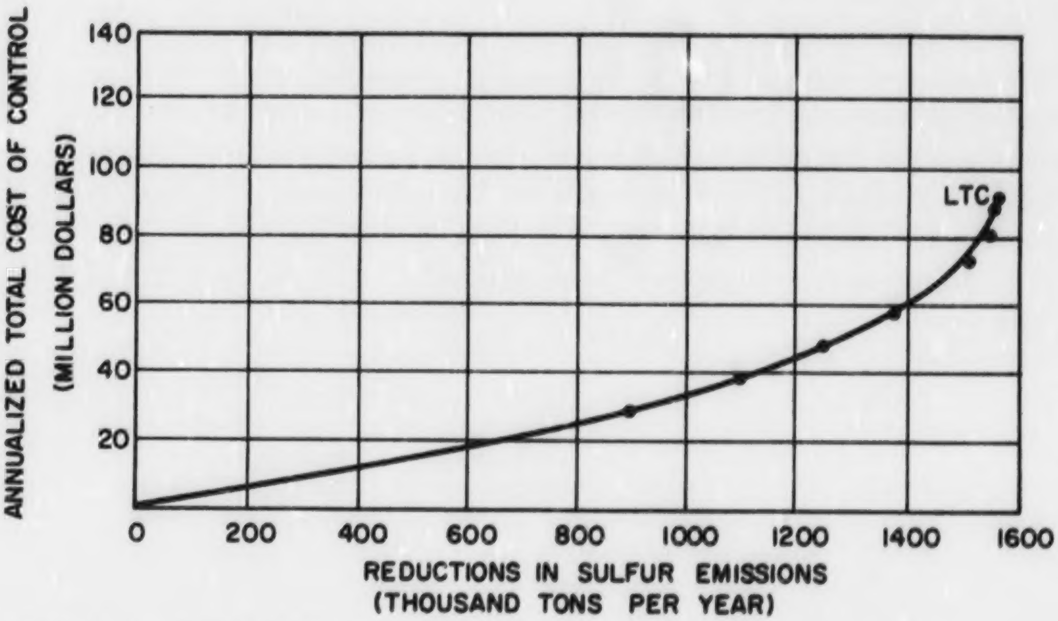

Figure D.1. Total cost* of reductions in sulfur emissions: primary nonferrous smelters--1978 (*does not include emissions tax payments) (Source: Research Triangle Institute).

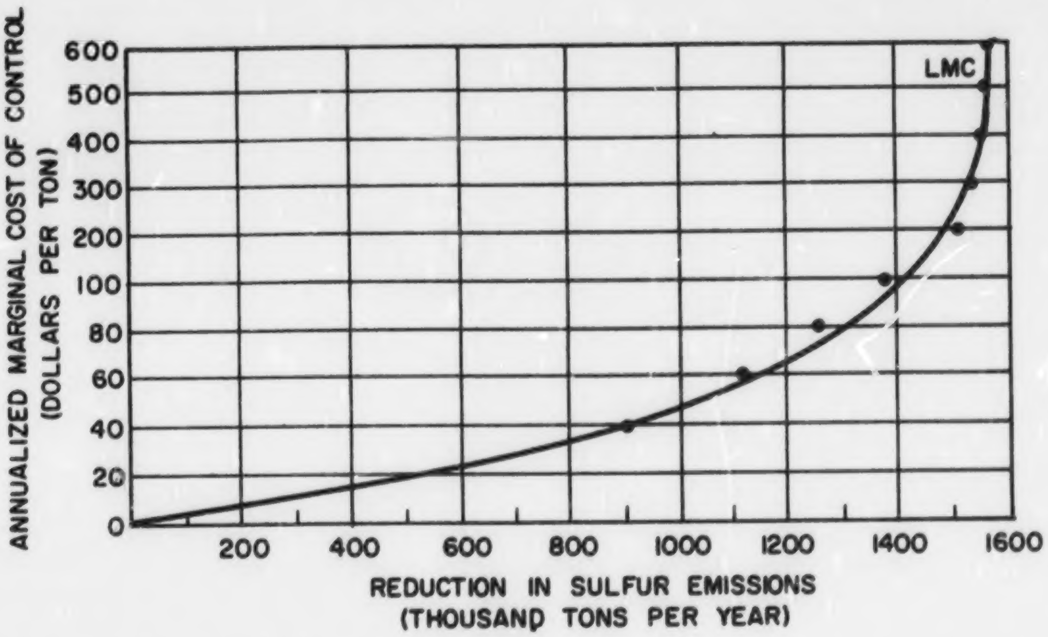

Figure D.2. Marginal cost* of reductions in sulfur emissions: primary nonferrous smelters (*does not include emissions tax payments) (Source: Research Triangle Institute).

Appendix E: THE PROJECTED MARKET FOR RECOVERED SULFUR

E.1 Introduction

Several of the alternatives for controlling sulfur oxide emissions result in the recovery of marketable sulfur or sulfuric acid. The future market for those products may influence the choice of emissions control and the net cost to the industries controlling sulfur emissions. Therefore, it is desirable to examine briefly the market for sulfur.

Sulfur is a naturally occurring inorganic mineral with many industrial uses, especially in the form of sulfuric acid. The largest use is in fertilizer production which consumes about one-half of all production. To a lesser extent, it is also used in making steel, rayon, paper, nonferrous metals, and chemicals.

E.2 Major Sources of Sulfur

Sulfur is mined from subterranean sulfur domes (native sulfur) and is also produced as a byproduct of some industrial processes, principally in the refining of sour oil and gas. Imports, primarily from Mexico and Canada, also supply portions to the U.S. market.

The share of the U.S. sulfur market enjoyed by native sulfur has been declining fairly regularly over the past 20 years. The smelter acid share has been fairly constant. The decline in the native sulfur share results from an increase in byproduct sulfur recovery which has increased over fourfold in the last 20 years.

E.3 Consumption of Sulfur

The apparent consumption of sulfur in the United States has been increasing about 2.8 percent annually since 1950, reaching 10.0 million tons* in 1970.†

The demand for sulfur is derived from the demand for fertilizers and other products for which sulfur is a major component. In the past,

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*Sulfur quantities are usually measured in long tons (2,200 pounds); however, for purposes of consistency within this report all figures here have been converted to the more common short ton (2,000 pounds).

†U.S. Department of Interior, Bureau of Mines, Minerals Yearbook, 1970, Washington, D.C., p. 1054.

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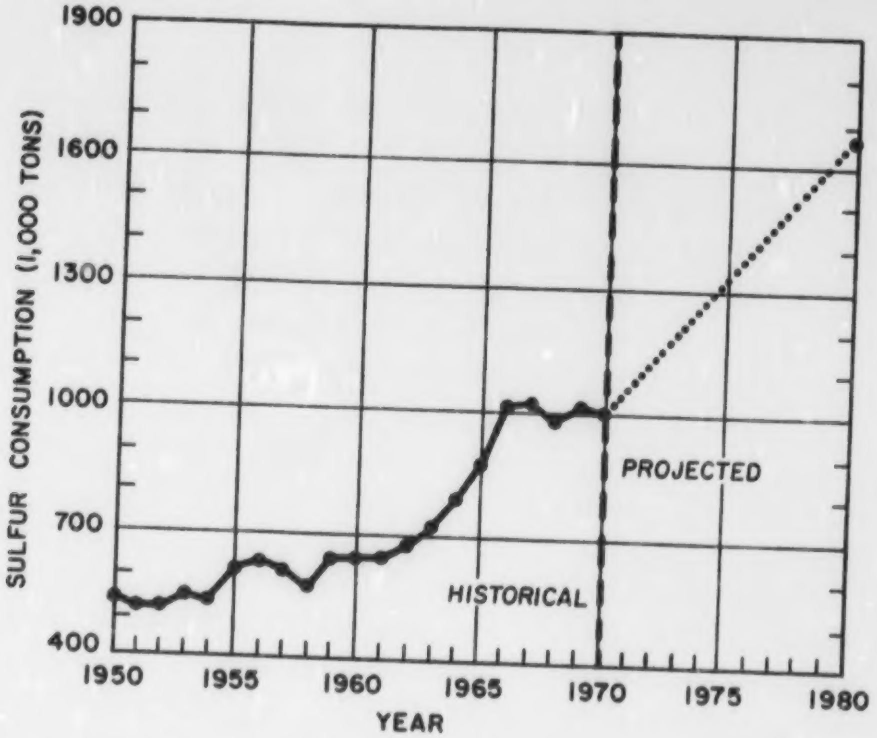

Figure E.1. Sulfur consumption trends (Source: Historical data, Department of the Interior: Projections, Research Triangle Institute).

there has been a close relationship between gross national product (GNP) and sulfur consumption in the United States. Given the inelastic demand for sulfur at the low prices, as reported in several studies,* and the prospects for continued depressed prices, a reasonable projection of sulfur demand for use in this study was obtained by extending this historical relationship to 1980. Based on a projected 1980 GNP of $1,155 billion,† sulfur consumption in 1978 is expected to be 15.1 million tons (see fig. E.1), 5.1 million tons above the 1970 estimate. With the increasing production of sulfur on a worldwide basis, it appears unlikely that the export demand will grow. Therefore,

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*M. H. Farmer and R. R. Bertrand, Long-range Sulfur Supply and Demand Model, Report GRU.1GM.71. Esso Research and Engineering Company, Linden, New Jersey, November 1971, p. 6.

†U.S. Department of Labor, Bureau of Labor Statistics, Patterns of U.S. Economic Growth (1980 projections of final demand, interindustry relationships, output, productivity, and employment), Bulletin 1672, Washington, D.C., U.S. Government Printing Office, 1970, p. 43.

Table E.1. Projected sulfur emissions--1978*

Emissions source	Sulfur emissions (thousand tons)
Steam electric plants	11,396
Area sources	5,679
Petroleum refineries	772
Sulfuric acid production	376
Primary nonferrous smelters	1,650
	19,873

*Assuming only the implementation of the New Source Performance Standards.

Source: Research Triangle Institute.

the projected U.S. consumption is expected to reasonably reflect the total market for U.S. sulfur.

As shown in table E.1, the projected 1978 uncontrolled sulfur emissions from the major sources under consideration in this study are about 20 million tons, an amount in excess of the projected production of sulfur. Any significant reduction in sulfur emissions and recovery and sale of sulfur could account for a substantial share of the projected growth in production. Such an eventuality will have a depressing effect on sulfur prices.

E.4 Prices of Sulfur

The price of sulfur is a function of the interrelationship of sulfur demand and supply. The demand for sulfur is derived from the demand for products where sulfur is used as a raw material. The supply of sulfur is based not only on the costs of mining sulfur but also on the availability of recovered sulfur which will be recovered, regardless of price, and sold for whatever price it will bring.

Figure E.2 shows the trend in sulfur prices over the past 20 years. For a long period beginning in 1947 and extending through 1966, sulfur prices edged up about 2.4 percent annually. However, beginning in December 1966, sulfur prices began to rise rapidly, averaging a 2.7

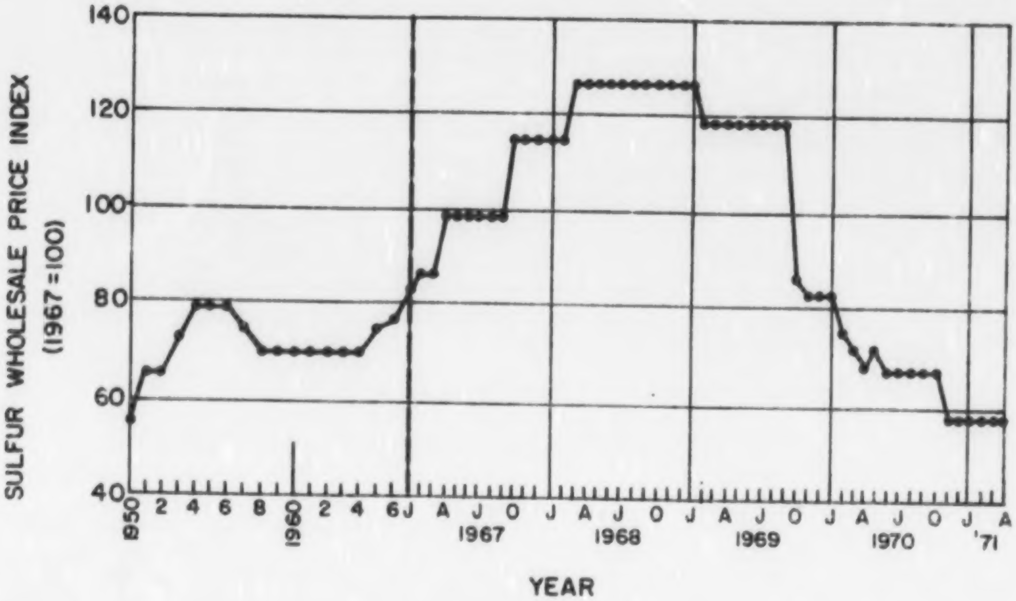

Figure E.2. Sulfur price index (Source: Department of Labor).

percent increase per month for the next 15 months. Between September and October of 1967, prices jumped 16 percent. In 1968, prices were relatively stable. Then early in 1969, they began to decline rather precipitously, finally reaching a level in 1971 of half their 1969 high.

The collapse of sulfur prices in 1969 is attributed to several causes, among them being:* (1) the drop in fertilizer demand due to overcapacity, (2) the expansion of pyrite roasting capacity in Europe, (3) the start-up of a large Frasch process operation in west Texas, (4) the expansion of modified Frasch process production in Poland, (5) expanded recovery of elemental sulfur by desulfurization of petroleum, (6) the increase in the recovery of acid from smelter gas, and (7) the U.S. business recession.

Published data on absolute value of current prices is unavailable because the Frasch process producers stopped publishing prices in 1969. However, by using the Bureau of Labor Statistics price index with the 1968 price of $38 per ton for crude, domestic, dark, bulk sulfur, as reported in the Oil, Paint, and Drug Reporter, the 1971 price can be estimated as about $20 per ton. It appears that $20 per ton represents the low end of the price range for Frasch sulfur; prices may be as much as $14 higher depending on the port of delivery. Recovered sulfur prices are a different matter. One Southwest oil refiner quotes prices of $14 to $25 per ton f.o.b. the refinery.* Many large buyers, however, are willing to pay a premium for Frasch process sulfur to obtain needed quantities and to help assure future availability.

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*M. H. Farmer and R. R. Bertrand, Long-range Sulfur Supply and Demand Model. Report GRU.1GM.71, Esso Research and Engineering Company, Linden, New Jersey, November 1971, p. 3.

It appears that future prices will continue to be depressed even without additional recovery by the large increases expected in Canadian capacity and continued growth in the amount recovered, especially from sour gas and from smelter gas. Furthermore, if ocean shipment of liquid sulfur becomes a reality, Canadian sulfur may be competitive with domestic sulfur in the largest U.S. sulfur market, the Florida phosphate industry.

The long-run upper limit on the price of sulfur is determined by both the cost of obtaining sulfur from its various sources and by the cost of alternative manufacturing processes that avoid the use of sulfur.† One report placed the costs of sulfur production between $10 and $43 per ton depending on source (see table E.2). The lower limit is indeterminate.

In summary, because of the downward pressures on sulfur prices and the likelihood of additional recovery of sulfur from controlling sulfur emissions, we believe that valuing the recovered product at a high price appears unwarranted. Most optimistically, the recovered product could be sold at prevailing market prices. This outcome would appear reasonable only if the product is not recovered in amounts large enough to significantly increase supplies and cause prices to decline. At the other extreme, if increased recovery of sulfur products results in substantial increases in supply without significant increases in quantity demanded, then the total value of sales may actually decrease.

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*C. W. Winton, "Dark Cloud on Sulfur's Horizon," Chemical Week, February 10, 1971, p. 31.

†M. C. Manderson, "The Sulfur Outlook," Chemical Engineering Progress, November 1968, pp. 47-53.

Table E.2. Sulfur production costs by source

Source	Cost per long ton
Frasch	
Low cost	$10
Medium cost	15
High cost	23
Sour gas	
Natural gas	15
Refinery	20
Smelter gas	18
Pyrites	35
Gypsum	35
Other native	35
Utility stack gas	43

Source: M. C. Manderson, "The Sulfur Outlook," Chemical Engineering Progress, November 1968, pp. 47-53.

This is a reasonable possibility given the inelastic demand for sulfur. Finally, in industries that use sulfur as an input and that recover more of the product due to a tax on their emissions of sulfur, the recovered product may be used as a substitute for purchased sulfur. In this case, the recovered sulfur should be valued at prices reflective of the sulfur cost savings. In many cases, this possibility appears most likely. For this analysis of a tax on sulfur emissions, the approximate current price, $20 per ton, and lower prices more reflective of the likely increase in sulfur supply, $10 and $0, have been selected as alternative future values for the marketable, recovered sulfur and for sulfuric acid.

Appendix F: THE EFFECT OF THE CORPORATE TAX STRUCTURE ON THE PROJECTED EMISSION LEVELS.

The purpose of this appendix is to analyze the effect of ignoring corporate income taxes and tax preferences on the levels of emission reductions that are projected in this study.*

The following variables will be used:

θ = corporate income tax rate, $(0 < \theta < 1)$;
ϕ = sulfur tax rate, dollars per pound;
E_j = sulfur emissions per period under j^{th} control option $(j = 1, \ldots, m)$, pounds per year;
K_j = investment cost of the j^{th} control option, dollars;
V_j = variable cost per period under the j^{th} control option;
d = depreciation rate per period, $(0 < d < 1)$;
n = planning horizon, in years;
r = cost of capital;
PV = present value of the anticipated cash outlay over the period n, in dollars.

Assume that the emissions tax payments (ϕE_j) are fully deductible from gross income and that the plant seeks to minimize the present value of its anticipated cash outlays for sulfur waste management. Under these assumptions the plant saves θ dollars in income taxes for each dollar it spends on emissions taxes and variable control costs, and for each dollar in depreciation it can charge against current gross income. Consequently, a dollar spent on emission control does not actually cost the plant a dollar; rather, it costs $(1-\theta)$ dollars. These ideas can be expressed symbolically.

The total emission-control-related variable operating costs (TVC) for a plant will be the sum of the variable costs (V_j) associated with the j^{th} control option and total emission taxes which equal the tax rate (ϕ) times the emissions (E_j) that would remain after the implementation of j^{th} control option:

$$TVC_j = V_j + \phi E_j \qquad j = 1, \ldots, m \qquad (1)$$

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*See Richard D. Wilson and David W. Minnotte, "Government/Industry Cost Sharing for Air Pollution Control," Journal of the Air Pollution Control Association, XIX, No. 10 (October 1969), pp. 761-766, for a detailed discussion, with examples, of these tax considerations.

Total emission-control-related depreciation expenses (DPR_j) during any period will be:

$$DPR_j = d\,K_j \qquad j = 1, \ldots, m \qquad (2)$$

The model used in this study assumes that TVC_j is constant over time and that emissions (E_j) associated with the j^{th} option are known. Consequently, during the first year of operation with the control equipment in place, the plant must make a cash outlay for the capital cost of the device (if any) and for the variable costs associated with the control option; during each succeeding period, outlays are required for only the variable costs. The discounted present value of the costs associated with the j^{th} control option is:

$$DPV(\text{costs})_j = \left[\sum_{t=0}^{n} \left(\frac{1}{1+r}\right)^t (V_j + \phi E_j)\right] + K_j \; . \qquad (3)$$

The discounted cash value of the benefits of the j^{th} control option is the discounted stream of income tax savings which is:

$$DPV(\text{benefits})_j = \sum_{t=0}^{n} \left(\frac{1}{1+r}\right)^t \theta(V_j + \phi E_j + d\,K_j) \; . \qquad (4)$$

The method of choosing among control options in this study was equivalent to choosing the option for which Eq. 3 was minimized.* However, the income tax consideration implies that savings associated with control options are not considered under the criterion of Eq. 3. The rational manager will consider net costs; i.e., the difference between Eqs. 3 and 4:

$$DPV(\text{net cost})_j = (1-\theta)\left[\sum_{t=0}^{n}\left(\frac{1}{1+r}\right)^t (V_j + \phi E_j)\right] + K_j\left[1-\theta\left\{d\sum_{t=0}^{n}\left(\frac{1}{1+r}\right)^t\right\}\right] \quad (5)$$

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*To see this, divide both sides of Eq. 3 by the discount factor. This yields the annualized expenditure whose present value is given by Eq. 3:

$$\text{Annualized Cost}_j = V_j + \phi E_j + K_j \Big/ \sum_{t=0}^{n}\left(\frac{1}{1+r}\right)^t \; .$$

The method of this study was to predict that plants would choose the control option which minimizes annualized cost; formally equivalent to choosing the option which minimizes Eq. 3.

If Eq. 5 is divided through by (1-θ), it is different from Eq. 3 only in the coefficient on K_j. Given that the annual depreciation rate, d, is the reciprocal of the number of years, n, over which the equipment is depreciated, it is readily obvious that that coefficient is greater than unity.*

Some tentative conclusions seem warranted in comparing Eqs. 3 and 5. First, all costs appear to be overstated by using Eq. 3. Because of the considerations mentioned in the foregoing paragraph, the overstatement would appear to be somewhat less than a factor of $1/(1-\theta)$. For example, if the corporate income tax rate is 50 percent (θ=0.5), the overstatement of costs predicted by Eq. 3 would be somewhat less than a factor of 2. However, Eq. 5 also indicates that the effective emissions tax rate, ϕ, is overstated by a factor of $1/(1-\theta)$ in Eq. 3 since all emissions tax payments are deductible expenses for income tax purposes. Consequently, the behavioral predictions of this report are probably not too affected, since both the effective tax rate and net costs were overstated by about the same factor.

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*Define α ($0 \leq \alpha \leq 1$) as

$$\alpha = d \sum_{t=0}^{n} \left(\frac{1}{1+r}\right)^t .$$

Then the coefficient, a, on K_j in Eq. 5 is

$$a = \frac{1-\theta\alpha}{1-\theta} .$$

If α=1, a=1. If α=0, a=$1/(1-\theta)$. Therefore, if the income tax rate is 50 percent (θ=0.5), the upper bound on a is 2.

Appendix G: SOME ASPECTS OF SULFUR EMISSION TAXES IN THE PRESENCE OF ADVANCING CONTROL TECHNOLOGY FOR POWER PLANTS

G.1 Introduction

Most of the conclusions of this report are based on the assumption that the producer-emitter makes his input choices in a static environment, with certain knowledge of input costs and a finite set of alternative inputs. One assumption was that only three hardware control options (dry limestone, wet limestone, and magnesia base scrubbing) would be available to the power plant, at a known cost per unit of production capacity in 1978. The purpose of this appendix is to reexamine that assumption and its effect on the results of this study in the light of other control alternatives that are expected to be available beginning in 1980.

Whereas regulations define specific reductions that must be achieved by all plants that comply with these directives, an emissions tax policy grants decisionmakers the latitude to avoid or to delay installing control devices. The use of a tax allows them to combine tax payments, to switch fuel, and to remove sulfur from flue gases to the extent that they deem economical. This additional flexibility not only induces efficiency in the reduction of sulfur emissions, resulting in equalization of marginal emissions reduction costs and minimization of total reduction costs (net of taxes) among plants, but also adds an element of uncertainty to the projected pattern of emissions reductions over time. This is a particularly important consideration in view of imminent improvements in control technology, for it implies that the plant may economize on resources in the long run by forfeiting tax payments in the near future to avoid getting tied into an inefficient, but currently available, control technology. Specifically, this analysis attempts to illustrate the motivations for and the extent of delays in control activities that could result from changes in assumptions regarding flue gas desulfurization equipment costs, operating characteristics, and availabilities.

Section G.2 reviews some of the technical aspects of expected post-1978 sulfur oxide control alternatives along with some preliminary estimates of the expected costs (per unit of capacity) of this equipment. In section G.3, some of the theoretical aspects of analyzing the producer-emitter's response to a sulfur emissions tax are discussed. That analysis sets the framework for the preliminary empirical investigation of these considerations in section G.4.

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G.2 Some Expected SO_2 Control Alternatives for Power Plants, 1980-1985

Besides dry and wet limestone and magnesia base scrubbing--all projected to be available by 1978--there are several other SO_2 control options that currently appear attractive and amenable to practical application between 1980 and 1985. These options may be categorized as: (1) new flue gas cleaning technologies and (2) alternative low sulfur fuels. Another set of options, also mentioned here, are those that must be incorporated in new power plants, either as a nonconventional steam-generation system (nuclear fission) or as a markedly different method of conventional fossil fuel combustion (fluidized bed and combined cycle power system). Table G-1 at the end of this section summarized the anticipated costs, technical references, and dates of availability for the control options discussed here.

G.2.1 SO_2 Control Alternatives for Existing Power Plants

Two new control hardware options that are both representative and--among the emerging technologies--economically attractive are expected to become viable by 1980. They are the citrate and the double alkali SO_2 removal processes.

G.2.1.1 Citrate SO_2 Removal Process. The citrate process employs a scrubbing sodium citrate solution. This solution scrubs the flue gas stream by dissolving the SO_2 gas component into the solution which is then reacted with hydrogen sulfide (H_2S). The chemical reaction generates solid sulfur which becomes a marketable byproduct.

Although the expected removal efficiency of this process, 90 to 95 percent, is about the same or slightly greater than those projected for wet limestone and magnesia base scrubbers, the anticipated initial cost of the system is somewhat lower, estimated approximately at $39 per kilowatt of installed capacity. On an annualized basis, these capital costs, plus operating, maintenance, and servicing costs, are roughly projected at 1.95 mills per kilowatthour of output (assuming average machine load factors and the absence of credits for the sale of recovered sulfur).

G.2.1.2 Double Alkali SO_2 Removal Process. The double alkali system is similar to the wet limestone system in that its expected removal efficiency is only slightly higher, 90 percent compared to 85 percent, and in that it is a "throwaway" process. No marketable sulfur product is generated.

In this process a soluble alkali composed of a sodium salt (like Na_2SO_3) is used to strip SO_2 from the flue gas. This sulfur-bearing solution is then regenerated by reacting it with an insoluble alkali such as lime or limestone. The output from this reaction is a reusable alkaline scrubbing solution and a throwaway sludge, such as calcium sulfite.

The estimated cost of this process, projected to be available in 1980, is of the order of $24 per installed kilowatt. Annualized costs, including operation, maintenance, and servicing costs, are projected at 1.75 mills per kilowatthour under the previously mentioned assumption of average plant operating factors.

G.2.1.3 Gasified Coal. Current energy research indicates that the gasification of coal is both practical and attractive from the standpoint of emissions reduction. This process appears capable of generating a synthetic gas whose caloric content averages about 950 Btu's per cubic foot, compared to an average of 1,000 Btu's for natural gas. The synthetic gas would have a sulfur content of about 0.1 percent. A plant consuming 3 percent sulfur coal containing a comparable heat input would have to achieve a 99.5 percent sulfur removal efficiency to achieve the same emissions reductions that would accompany the use of this synthetic gas. Current best judgment indicates that the cost of producing gasified coal, not deemed feasible until 1985, will be about 60 cents per million Btu's.

G.2.2 SO_2 Control Options for New Power Plants

Conventional power plants have dual deficiencies: (1) all the sulfur in the fossil fuel being combusted gets volatized and, hence, becomes gas entrained, and (2) these plants reflect low thermal efficiencies (i.e., high fuel input to power output ratios). Some new power generating techniques remedy one or the other of these problems. These new power systems include a modification of conventional technology, fluidized bed combustion; a new concept in coal fired power systems, COGAS; and nuclear power plants.

G.2.2.1 Fluidized Bed Combustion Process. The fluidized bed process allows the combustion of coal in a bed which contains an active material such as a limestone dolomite sorbent. Between 90 and 95 percent of the sulfur in coal is diverted away from entrainment in the combustion off-gases as a result of chemical reactions which accompany this process. The pressurized (as opposed to atmospheric) fluidized bed combustion process appears the most economical of those options which follow this general concept.

This process is not expected to be commercially available until 1984 at the earliest. Current engineering judgment suggests that the capital cost of a plant equipped with the fluidized bed process will be in the neighborhood of $190 per kilowatt (compared to about $120 for current conventional plants) and will require about 6.30 mills per kilowatthour to operate (compared to 6.22 for a conventional coal-fired power plant).

G.2.2.2 Combined Cycle Power Systems. Combined cycle power production techniques combine the efficient use of energy with virtually emission-free power generation. Of the several such systems under development, the COGAS process is in the most advanced stages and appears capable of application by 1985. The acronym COGAS refers to this system's combination of coal to gas conversion with the advanced power cycle concept. The COGAS process generates a virtually sulfur-free gas from high sulfur and high ash content coal; the gas is very low in heat content, on the order of 60 Btu's per cubic foot. Once generated, the low-Btu, pressurized gas is fired in a combustion turbine. The residual energy in the flue gas from this combustion is then captured in a heat recovery boiler to which supplemental fuel is fired to produce superheated steam that is used to drive a steam turbine. This process promises not only 99-percent sulfur removal efficiencies but also increased thermal efficiencies (a measure of output to fuel input requirements) of as much as 55 percent. The projected investment requirements of such a system are about $127 per kilowatt of installed capacity; annualized operating costs are estimated at 5.20 mills per kilowatthour.

G.2.2.3 Nuclear Power Plants. Nuclear fission is a sulfur-emission-free alternative to fossil fuel combustion for central station power generation. The basic way in which nuclear power generation differs from conventional techniques is in the way the steam-generating heat is produced. All forms of nuclear power generation produce heat through a controlled nuclear fission process. Conventional reactors consume the fissile material and promise to create upward pressure on the price of uranium as those reserves become depleted. As opposed to that, the not yet fully developed breeder reactor actually generates more fuel than it consumes. The details of these production technologies are well beyond the scope of this report. Suffice it to say that the pressurized water reactor was chosen as the most representative of conventional reactors and that its investment requirements run about \$175 per installed kilowatt; its annualized cost is on the order of 6.56 mills per kilowatthour. The breeder reactor would cost about \$240 per installed kilowatt and on an annualized basis would cost about 6.46 mills per kilowatthour to operate. If fuel prices rise steeply and if the breeder reactor becomes fully operational, its fuel economy could obviously stimulate large-scale shifts toward this as the preferred power production technique.

G.2.3 Summary

Table G.1 summarizes the cost, operating, and availability characteristics of some attractive alternatives that are expected to be available for reducing sulfur emissions from power generation before the middle of the next decade. Technical references of those projections are also cited. For reference, the table also includes current estimates of costs relating to conventional oil- and coal-fired power plants.

G.3 Theoretical Aspects of Producer Responses to the Emissions Tax Over Time

Throughout this study it has been assumed that the power plant is the decisionmaking unit and that the plant's output is determined exogenously. Consequently, it is assumed that the plant's objective is to minimize costs subject to the output constraint. Allowing that constraint, this section attempts to derive a simple model of the producer's decision function in a dynamic setting. These general concepts are used in the following section in conjunction with the results of the computerized model and the data of table G.1 to perform a preliminary analysis of the implications inherent in the exclusive use of an emissions tax as the policy instrument of choice in achieving emissions reductions.

G.3.1 A Simple Model of Cost Minimization Without Emissions Control Policies

An existing power plant has been assumed in this report to require a fixed flow of fuel heat input (Btu_t) each year. That heat input is the product of the physical flow of fuel (F_{jt}), say tons, and the heat content (h_j) per physical unit, say Btu's per ton. The total fuel input from the chosen fuel in any year, measured in Btu's, can be stated as

$$Btu_t \equiv h_j F_{jt} \qquad (G.1)$$

Table G.1. Projected costs and availability of sulfur emissions control alternatives for power production, 1980-1985

Alternative	Initial capital requirements[a] ($/kilowatt)	Variable costs[a]		Anticipated date of commercial availability	Sulfur emissions reduction percent[b]	Technical reference
		Mills/kilowatthour	Cents/million Btu			
Conventional power plants:						
Coal fired[c]	175	6.22		Currently	None	e
Oil fired[c]	168	6.94		Currently	None	e
Add-on technologies:						
Citrate process	39	1.95		1980	90-95	f
Double alkali process[d]	24	1.75		1980	90	f
Gasified coal	0		60	1985	99.5	g
Advanced fossil-fueled plants:						
Fluidized bed combustion	190	6.30		1983	92	h
Combined cycle (COGAS) system	127	5.20		1985	99	e
Nuclear power plants:						
Conventional reactor	175	6.56		Currently	100	i
Breeder reactor	240	6.46		1985	100	i

[a] All costs are estimated in current dollars; the estimates are for an average 500 MW plant.

[b] These are based on comparisons with uncontrolled emissions from the combustion of 3 percent sulfur coal.

[c] These costs do not include the capital and variable input requirements of either sulfur or particulate control systems; the forms are given as the costs of add-on technologies.

[d] Cost estimates do not include credits for the sale of recovered sulfur.

[e] Robson, F.L., et al. Technological and Economic Feasibility of Advanced Power Cycles and Methods of Producing Non-Polluting Fuels for Utility Power Stratas, Final Report submitted to EPA by VARL under Contract Number CPA 22-69-14, 1970.

[f] Rochelle, G.T.,"A Critical Evaluation of Processes for the Removal of SO_2 from Power Plant Gas", Paper prepared for Air Pollution Control Association Meeting, June 1973.[2]

[g] Edison Electric Institute, Fuels for the Electric Utility Industry 1971-85, Edison Electric Institute, 1972.

[h] Archer, D.H., et al. Evaluation of the Fluidized Bed Combustion Process, Final Report submitted to EPA by Westinghouse Research Laboratory, under Contract Number CPA 70-9, 1971.

[i] Hottel, H.C. and J.B. Howard, Chapter 4, "Nuclear Power", in New Energy Technology; Some Facts and Assessments, MIT Press, 1972.

where

Btu_t = annual fuel heat input in Btu's at time t ;

F_{jt} = physical flow of j^{th} fuel input at time t ;

h_j = Btu's per physical unit of the j^{th} fuel.

If the plant heat rate (required Btu's per kilowatthour output) is constant ($\overline{HR}$), one may alternatively express the required fuel input in terms of the heat rate and output:

$$Btu_t = (\overline{HR})(kWh_t) \tag{G.2}$$

where

$\overline{HR}$ = the plant heat rate (required Btu's per kilowatthour output)

kWh_t = required plant output in kilowatthours at time t.

By assuming that the decimal percent, by weight, of the j^{th} fuel that appears as volatized sulfur in the combustion off-gases is fixed at α_j, sulfur emissions (SU_{jt}) that would occur without control devices during any year can be stated as:

$$SU_{jt} = \alpha_j F_{jt} \tag{G.3}$$

where

SU_{jt} = annual sulfur emissions using the j^{th} fuel at time t ;

α_j = decimal percentage sulfur content of the j^{th} fuel, by weight.

If one assumes that the capital cost of the power plant is sunk and that all variable costs besides fuel are proportional to the size, not output, of the plant, then the volume of sulfur emissions may be regarded as determined by the cost minimizing flow volume of fuel. If, for example, the cheapest fuel is 3 percent sulfur coal and the plant requires F_t^* tons to meet its heat input requirements, then sulfur emissions are $\alpha_k F_k^*$, where k is the index identifying 3 percent sulfur coal and where that product satisfies the constraint of Eq. G.2. The plant has no economic incentive to reduce emissions in the absence of emissions control policy.

G.3.2 Cost Minimization Over Time in the Presence of Emissions Control Policies

Either a regulation or a tax on emissions will force the producer to reconsider his emissions output decision. Assuming that there are m emission control technologies--the k^{th} one of which manifests an average decimal percentage collection efficiency of ϵ_k--and further assuming that only one such control device can be in place at any point in time, the producer can potentially achieve any one of k annual sulfur emission levels (E_{jkt}) for each fuel consumed where:

$$E_{jkt} = (1-\varepsilon_k)\ SU_{jt} \tag{G.4}$$

and where

ε_k = the sulfur collection efficiency of the k^{th} control technology;

E_{jkt} = annual sulfur emissions with k^{th} technology in place using the j^{th} fuel at time t.

Further assuming that the investment cost (I) of any control option is fixed and known in relation to the power plant's capacity (kW), one may state the initial pollution control capital requirement as:

$$I_k = A_k\ kW \tag{G.5}$$

where

KW = kilowatt capacity of the plant;

A_k = investment cost per kilowatt for the k^{th} control option;

I_k = initial capital requirement for k^{th} control option.

Also by assuming that the variable costs (V_{kt}) of operating the k^{th} sulfur removal system are proportional to plant output in kilowatthours per year (kWh_t), these costs can be expressed as

$$V_{kt} = B_k\ kWh_t \tag{G.6}$$

where

V_{kt} = annual variable costs associated with the k^{th} sulfur removal system;

B_k = variable costs per kilowatthour.

The annual tax bill (TAX) due from the power plant is the tax rate (θ) times the flow volume of sulfur emissions from the plant during the year.

$$TAX_{jkt} = \theta\ E_{jkt} \tag{G.7}$$

where

TAX_{jkt} = annual tax bill using the j^{th} fuel and k^{th} control technology at time t ;

θ = sulfur tax rate per ton of emitted sulfur.

In the presence of a sulfur emissions tax, the cost minimizing plant will make a concurrent decision regarding the appropriate combination of fuel and emissions control devices. If, for every one of the n fuels available, the decisionmaker anticipates a cost (P_i) per Btu that will obtain over a T-year planning horizon, the alternative anticipated annual fuel bills ($FUEL_t$) for the plant will be

$$FUEL_{jt} = P_j h_j F_{jt} \quad \text{or} \quad P_j Btu_t \tag{G.8}$$

where

$FUEL_{jt}$ = anticipated annual fuel bill using the j^th^ fuel;

P_j = anticipated price per Btu of the jth fuel over the T-year planning horizon.

The producer will choose the combination of fuel costs and investment outlays that minimizes the discounted present value (PV) of costs over that planning horizon. One may state the discounted present value of the cost of using the jth fuel and the kth control technology T* periods from now, assuming a current opportunity cost of capital of r dollars per dollar ($0 < r < 1$), as:

$$PV_{jk} = \left(\frac{1}{1+r}\right)^{T^*} I_k + \sum_{t=0}^{T} \left(\frac{1}{1+r}\right)^{t} Fuel_{jt} + \sum_{t=0}^{T^*} \left(\frac{1}{1+r}\right)^{t}_{\theta} SU_{jt}$$

$$+ \sum_{t=T^*}^{T} \left(\frac{1}{1+r}\right)^{t} \left(V_{kt} + TAX_{jkt}\right) \tag{G.9}$$

where

T* = the number of periods from the current period when the installation of the control device is anticipated;

r = the opportunity cost of capital.

The first two terms in this expression represent the discounted present value of the pollution control capital and fuel outlays, respectively. The third term is the discounted present value of tax payments on sulfur emissions during the future period when no hardware controls are anticipated. The last term reflects the discounted present value of the variable costs of operating the control device, once installed, and of the tax payments on the emissions that would remain.

The producer will choose the minimum cost combination of fuels and control hardware subject to the constraint, Eq. G.2, that the fuel input equals that necessary to produce the required output. For a plant meeting the constraint in Eq. G.2, one may alternatively express output using Eq. G.1 as

$$kWh_t = \frac{1}{\overline{HR}} h_j F_{jt} \qquad (G.10)$$

By using Eqs. G.2 through G.7, the dynamic cost minimization objective of Eq. G.9 may be written alternatively as

$$PV_{jk} = \left(\frac{1}{1+r}\right)^{T^*} A_k kW + \sum_{t=0}^{T} \left(\frac{1}{1+r}\right)^{t} P_j h_j F_{jt} + \sum_{t=0}^{T^*} \left(\frac{1}{1+r}\right)^{t} \theta \alpha_j F_{jt}$$

$$+ \sum_{t=T^*}^{T} \left(\frac{1}{1+r}\right)^{t} \left(\frac{B_k h_j}{\overline{HR}} + \theta(1-\varepsilon_k)\alpha_j\right) F_{jt} \qquad (G.11)$$

subject to: $h_j F_{jt} = (\overline{HR})(kWh_t)$.

Some general observations are already obvious from the model of Eq. G.11. First, deferring the investment an increasing number of years (increasing T*) will reduce the discounted present value of capital costs, the first term in Eq. G.11. However, offsetting that is the fact that the collection efficiency (ε_k) over those periods is zero, resulting in a higher tax bill, the third term in Eq. G.11. Furthermore, such a plan would probably involve the choice of a low sulfur fuel whose price (P_j) would be higher than that of a fuel that is economical when sulfur control technology is in place. This too would tend to increase the cost of deferring the control investment by increasing the size of the second term. On the other hand, the variable costs (B_j) of operating a currently available control device would be avoided entirely in the interim; i.e., the fourth term is zero for the first T* periods. Finally, other things being equal, a higher opportunity cost of capital is likely, ceteris paribus, to induce the deferment of investment in control technology, since that action would reduce the impact of pollution control investment costs, the first term in Eq. G.11.

By using the data in table G.1 the sensitivity of plant behavior to variations in some of the parameters in Eq. G.11 is analyzed in section G.4. The general theoretical framework of Eq. G.11 is used there to predict plant responses under alternative assumptions regarding annualized control costs, tax rates, collection efficiencies, and the expected number of years (T*) from 1978 that will elapse before the control process is available.

G.4 A Preliminary Empirical Investigation of Sulfur Emission-Tax-Induced Delays in the Removal of Sulfur Oxides from Stack Gases

To provide insight into the types of effects that time and new technologies may have beyond those assumed for this study, three synthetic plant models were developed. The hypothesized operating parameters of these plants are given in table G.2. The table also reports approximate

Table G.2. Model plant parameters and projected SO_x removal costs

Plant size Parameters	Large, 1500 MW	Medium, 800 MW	Small, 350 MW
Annual Btu input (billion Btu's)	110,678.0	59,023.0	18,446.0
Annual kilowatthours output (million hours)	13,176.0	7,027.0	3,074.0
Annual uncontrolled emission rate (tons)	134,739.0	71,861.0	22,456.0
Annualized cost of control for processes:*			
Wet limestone	18.0	21.5	26.5
Magnesia base	17.8	20.2	25.7
Citrate	12.0	14.5	18.5
Double alkali	11.5	13.2	15.5

*Cents per million Btu.

Source: Research Triangle Institute.

annualized costs for two control processes, wet limestone and magnesia base scrubbing, that are attractive SO_x control options which were anticipated in other parts of this study. Also presented are anticipated annualized costs for two new technologies, the citrate and double alkali processes, expected to be available during the 1980's. The latter costs are extrapolations of those reported in table G.1.

The analytical technique used in this portion of the study was first to generate the costs of fuel switching only and the emissions tax payments that would occur at different tax rates for each plant size. These costs were projected using the basic computer model used throughout this study. Then the computer model was run again for each of three hypothetical plants, this time allowing the plant to institute cost minimizing combinations of either magnesia base or wet limestone scrubbing and fuel switching and tax payments.

In following the assumption in other parts of this report that the opportunity cost of capital is in the neighborhood of 12 percent, the "critical" level of annualized cost of a new technology available T* years from the present (for this analysis presumed to be 1978) was calculated as follows. The present value of the costs of fuel switching and tax payments over T* periods was computed. Similarly, the present value of the cost minimizing combination of currently available control options (assumed to be wet limestone and magnesia base), tax payments, and fuel switching was calculated. The "critical" value of the annualized costs of new technology options was then determined by division of the difference between the latter and former discounted costs by the appropriate discount factor.

These concepts can be stated briefly in algebraic notation. Where the annualized cost of presently available SO_x control options, including tax payments, is denoted as PT; that of fuel switching and tax payments as FS; the number of years until the new technology is available as T*; the opportunity cost of capital as r; and the "critical" value of the annualized cost of new technology and emissions tax payments as X, the point of indifference between choosing currently existing options and new options available T* years from the current year is defined by the following equality (the assumed planning horizon was 15 years):

$$\sum_{t=0}^{T*} \left(\frac{1}{1+r}\right)^t FS + \sum_{t=T*}^{15}\left(\frac{1}{1+r}\right)^t X = \sum_{t=0}^{15}\left(\frac{1}{1+r}\right)^t PT \qquad (G.12)$$

Since output from the basic computer model generated FS and PT and since r was assumed to be 0.12, the "critical" value (X) was calculated by the following equation:

$$X = \frac{\displaystyle\sum_{t=0}^{15} \left(\frac{1}{1+r}\right)^t PT - \sum_{t=0}^{T*} FS \left(\frac{1}{1+r}\right)^t}{\displaystyle\sum_{t=T*}^{15} \left(\frac{1}{1+r}\right)^t} \qquad (G.13)$$

The value given by Eq. G.13 represents the annualized cost of a new technology plus annual emissions tax payments above which the cost minimizing plant would choose to install immediately (1978) the present technology and below which it would choose to wait T* periods until the new technology was available. In the empirical work, the number of years the plant would have to wait for new technology was varied over three assumed values: 2, 4, and 6 years. For each of those values of T* and for each tax rate for which FS and PT were projected, Eq. G.13 was used to calculate the "critical" value.

Since the control cost portion of X, the sum of control costs and tax payments, depends upon the volume of emissions that remains after the application of the new control technology, alternative assumptions concerning the control efficiencies of new technologies were also made. The assumed efficiencies of control for projected SO_x control technologies were 90, 95, and 99 percent. The emissions rates in table G.2 then allowed calculation of the annual cost of tax payment at each tax rate and control efficiency. This then yielded a net remainder available for annualized costs of owning, maintaining, and operating the SO_x control hardware. Using the annual Btu inputs, also reported in table G.2, finally allowed a computation indicating the maximum cost, in cents per million Btu, at which the deferment of current investment in favor of future (cheaper) control processes would be more economical than immediate installation of stack gas cleaning devices. The loci of those critical costs are reported in figures G.1, G.2, and G.3 for the large, medium, and small hypothetical plants, respectively.

An example of the meaning of the curves in figures G.1, G.2, and G.3 follows. Suppose that a new control process would be available by 1982, 4 years beyond 1978, at an approximate cost of 12 cents per million Btu for a 1,500 MW power plant. Further assume that the process could achieve 95 percent collection efficiencies. Would the plant wait 4 years to install the new process and pay the emissions tax penalities in the interim? If so, over what ranges of tax rates? The middle panels (B) of the figures answer those questions. For tax rates below about 7 cents and above approximately 19 cents per pound of emitted sulfur, the hypothetical plant would choose to follow current options; i.e., to install one of the currently available technologies immediately. Between those anticipated tax rates, it would choose to wait 4 years until the new technology is available. This method can be applied for any number of options among the subject plant sizes.

The cause of the peaking over the mid-range of taxes (B panels) in all three figures is that the ratios of PT to FS (annualized present technology and fuel switching costs, respectively) in Eq. G.13 follows that same pattern, by causing the corresponding values of X and, in turn, the critical values presented in those figures to follow the pattern displayed there.

It is interesting to compare the costs of the two new technologies presented in table G.2 against these figures. Recall that the citrate process promises control efficiencies over the range of 90 to 95 percent while the double alkali process is expected to manifest a control efficiency of about 90 percent. Both are expected to be available by 1980, within 2 years of the beginning of the planning horizon. Using the cost data of table G.2, one can determine from figure G.1 that large plants (1,500 MW) would be expected to wait until those processes were available for any tax

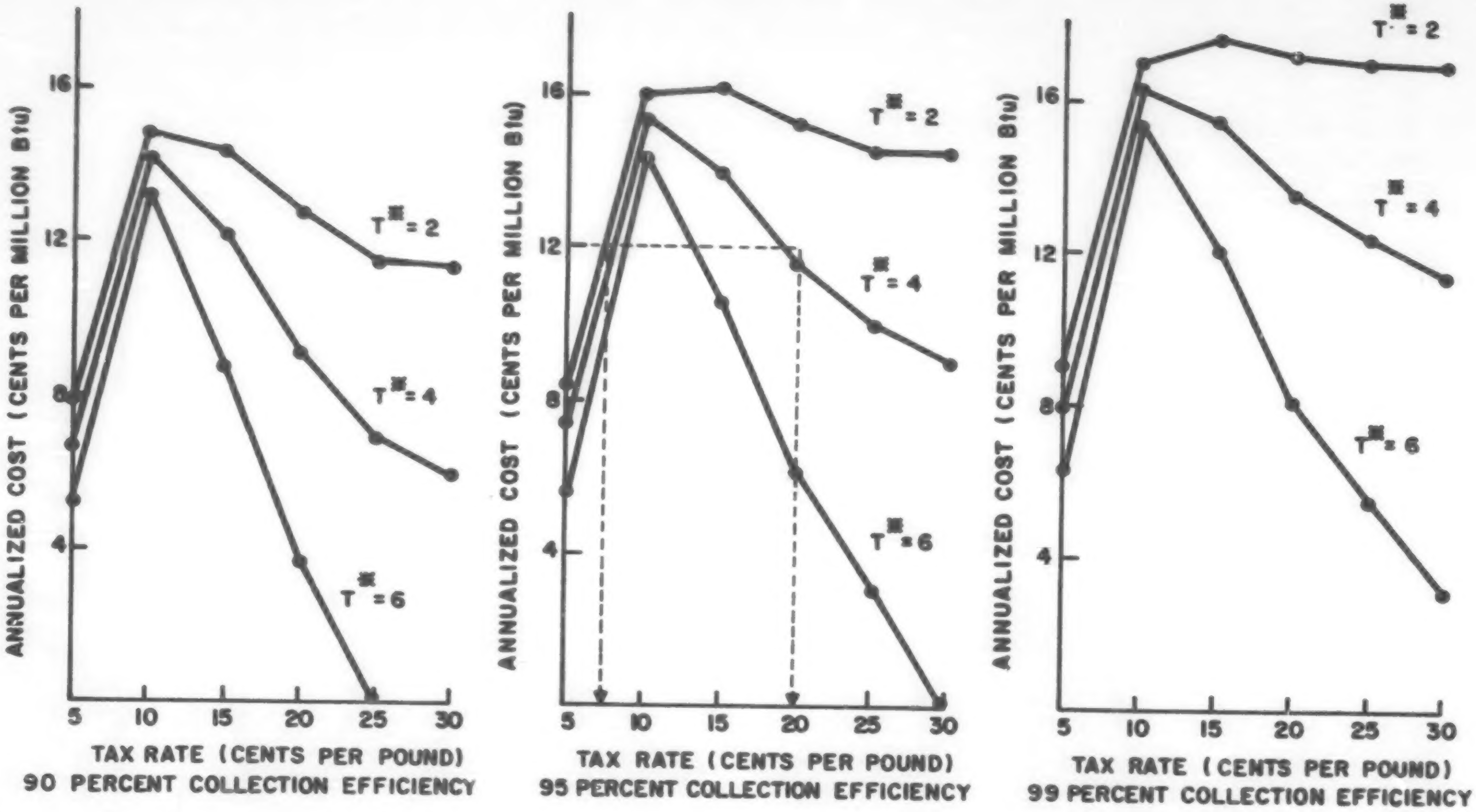

Figure G.1. Loci of anticipated costs of new SO_x control processes (available in T* years beyond 1978) below which a cost minimizing 1500 MW model power plant would defer SO_x stack gas cleaning.

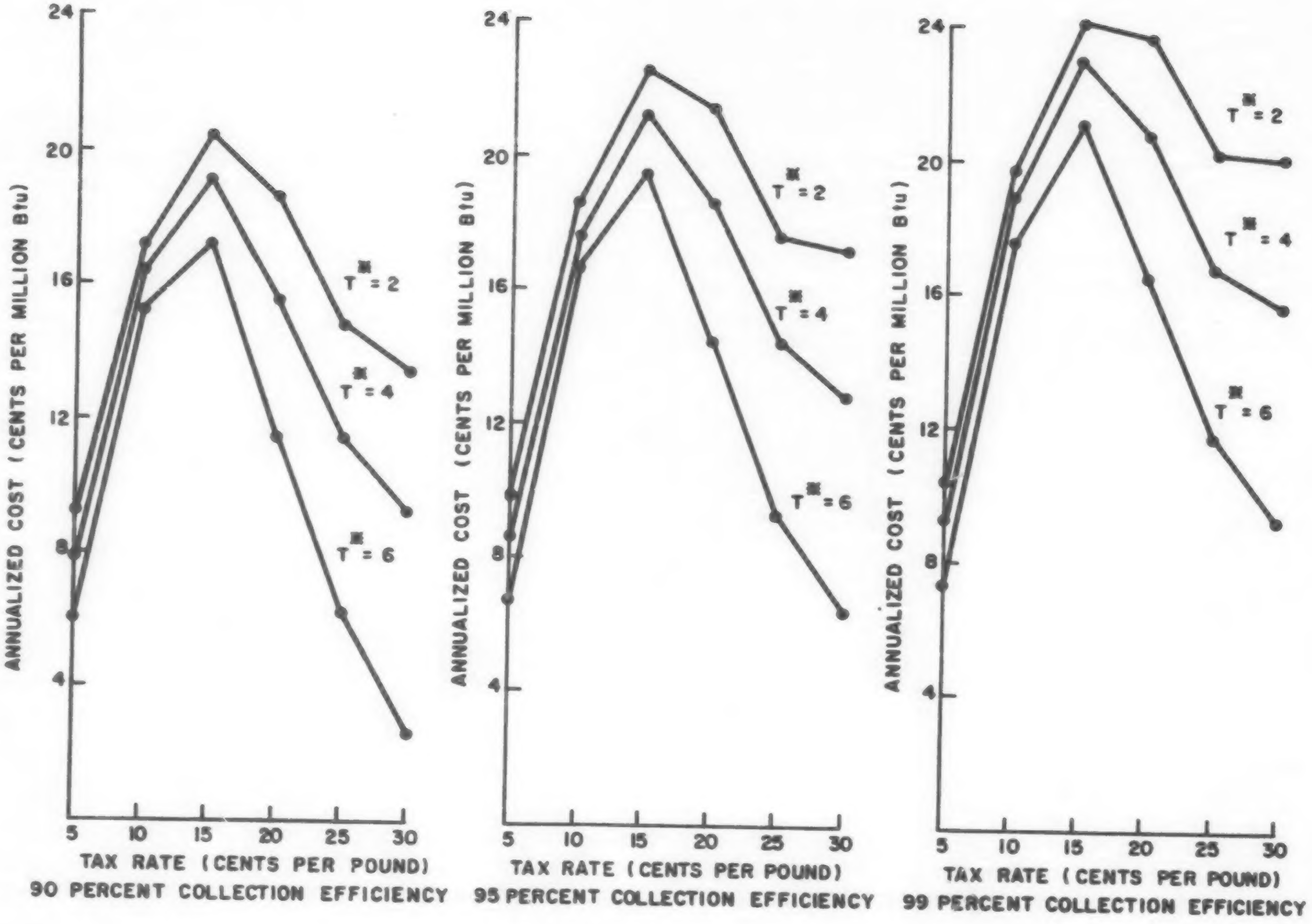

Figure G.2. Loci of anticipated costs of new SO_x control processes (available in T* years beyond 1978) below which a cost minimizing 800 MW model power plant would defer SO_x stack gas cleaning.

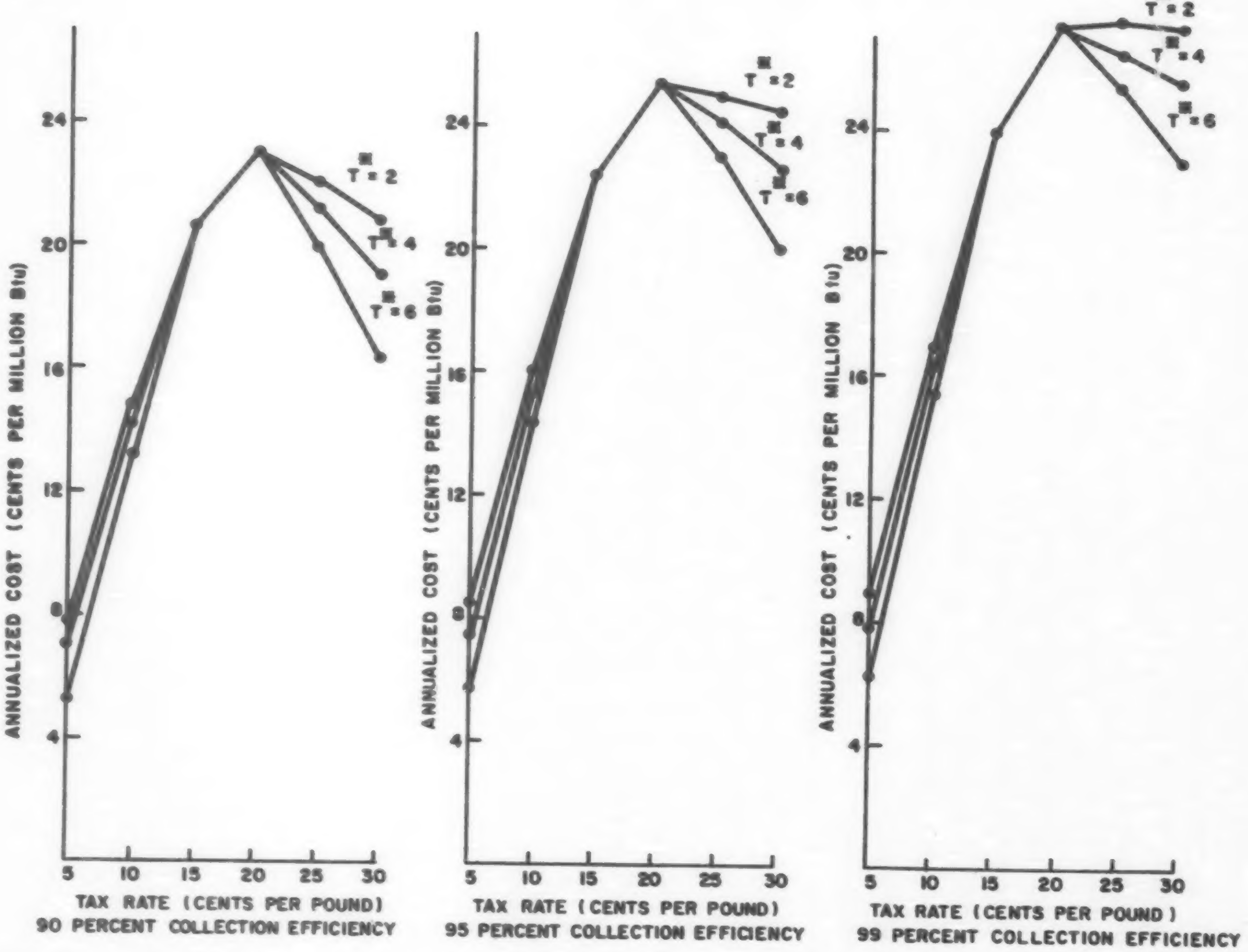

Figure G.3. Loci of anticipated costs of new SO_x control processes (available in T* years beyond 1978) below which a cost minimizing 350 MW model power plant would defer SO_x stack gas cleaning.

rates in excess of about 7 cents per pound of emitted sulfur at 90 percent efficiencies and for even lower tax rates if the control efficiency ranges up to 95 percent. Figures G.2 and G.3 indicate that virtually the same results would hold for medium- and small-sized plants. The choice of deferring or not deferring appear, for all three sizes, to be very sensitive in the range of tax rates between 5 and 10 cents, both reasonable values that have been suggested by some officials as feasible tax rates.

Quite obviously, this analysis is highly dependent on an array of assumptions about plant location, expected fuel prices, estimated costs of control options anticipated in 1978, and a multitude of other parameters. Yet it is useful in that orders of magnitude are identified and in that the directional affects of the time until new processes are available, of collection efficiencies, of tax rates, and of new source control costs are identified and, at least roughly, quantified. More complete investigations will await better refined cost models for new control options, improved knowledge of anticipated fuel costs, and intensive microanalysis of the ways in which firms, in practice, respond to uncertainty in environmental control policy parameters.

APPENDIX H: STATE-BY-STATE PROJECTIONS OF THE EFFECTIVENESS AND COSTS OF A TAX ON SULFUR EMISSIONS

The primary purpose of this study was to provide an initial projection of the effectiveness and costs of a uniform national tax on sulfur emissions. As demonstrated in ch. 5, the effects of such a tax on local air quality can be expected to vary from region to region across the country depending on local climatic conditions and on the type, size, and geographic distribution of polluting sources. Since the emissions response model developed for this study uses a listing of discrete sulfur emissions sources, it is possible to aggregate the behavior of the sources below a national level to obtain regional projections of effectiveness and costs. This has been done on a State-by-State basis in this appendix to provide insight regarding the possible regional differences in responses to a tax on sulfur emissions. The reader is cautioned, however, that these projections are very preliminary.

The projected State-by-State responses to a tax on sulfur emissions are shown in table H.1. Comparison of the projected responses for four States chosen for expositional purposes follows.

The cost of sulfur emissions control varies significantly from State-to-State due to differences in the type, number, and size of the emissions sources present. Marginal cost of control curves for Alabama, Indiana, New York, and Texas utilizing the tabular data are presented in figure H.1. The amount of reduction in emissions induced by the tax will vary considerably among these four States. For example, for a marginal cost of $300 per ton, sources in Texas could reduce emissions by 175,000 tons annually; those in Indiana, 700,000 tons annually. The remaining emissions for each State for alternative tax rates are shown in figure H.2.

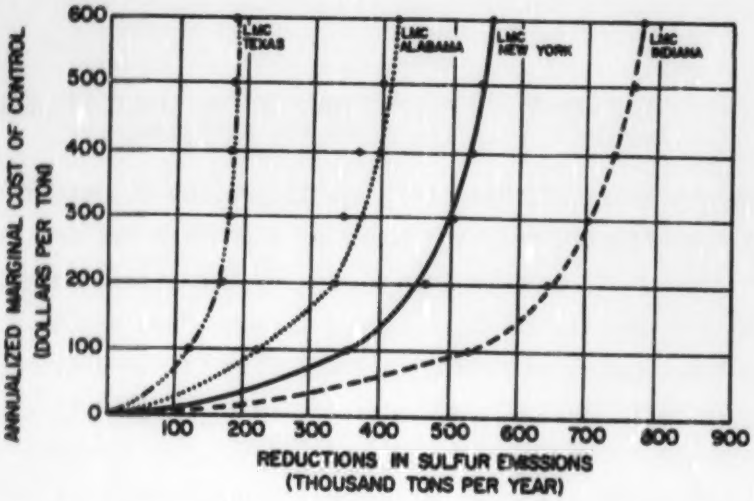

Figure H.1. Marginal cost of reductions in sulfur emissions from all major sources combined in selected States. (Source: Research Triangle Institute).

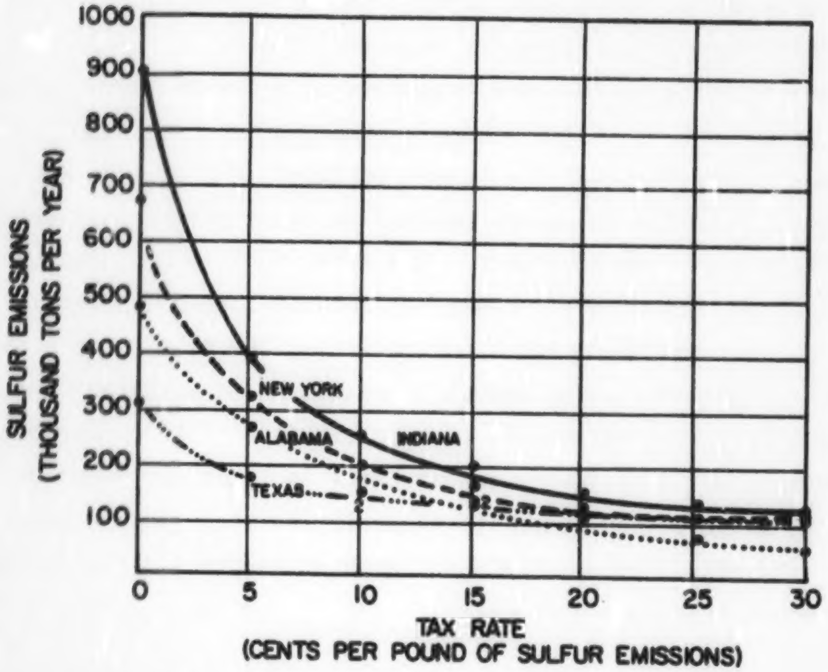

Figure H.2. Effectiveness of a tax on the sulfur emissions from all major sources combined in selected States. (Source: Research Triangle Institute).

Table H.1. Projected State-by-State responses to a national tax on sulfur emissions

State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
Alabama	0	482	-	-	-	-
	5	262	220	40,744	24,070	16,674
	10	146	336	1,446	766	670
	15	135	348	88,023	57,227	30,616
	20	128	355	105,421	63,861	41,560
	25	83	399	120,934	89,034	31,900
	30	58	424	131,707	106,388	25,319
Alaska	0	1	-	-	-	-
	5	1	0	92	0	92
	10	24	723	24,514	19,753	4,761
	15	1	0	232	28	204
	20	1	0	300	28	272
	25	0	1	348	127	221
	30	0	1	392	127	266
Arizona	0	764	-	-	-	-
	5	175	589	37,164	19,881	17,183
	10	38	725	42,757	35,348	7,410
	15	35	728	46,556	36,076	10,480
	20	30	734	49,977	40,753	9,224
	25	30	734	53,029	38,378	14,651
	30	30	734	55,918	38,512	17,506
Arkansas	0	13	-	-	-	-
	5	12	1	1,250	195	1,415
	10	6	7	2,222	931	1,291
	15	5	8	2,826	1,217	1,609
	20	4	9	3,316	1,583	1,732
	25	4	9	3,770	1,660	2,110
	30	4	9	4,216	1,694	2,523
California	0	212	-	-	-	-
	5	120	92	17,527	7,466	10,061
	10	90	122	30,210	14,816	15,995
	15	75	137	39,825	19,294	20,531
	20	70	142	48,527	22,175	26,352
	25	69	143	56,771	24,651	32,119
	30	68	144	64,721	26,340	38,381
Colorado	0	73	-	-	-	-
	5	53	20	6,207	2,336	3,871
	10	32	41	10,443	5,563	4,880
	15	22	50	13,795	8,255	5,540
	20	19	53	16,413	10,410	6,002
	25	18	54	18,637	10,848	7,789
	30	16	56	20,745	13,061	7,683

Table H.1. Projected State-by-State responses to a national tax on sulfur emissions (con.)

State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
Connecticut	0	131	-	$ -	$ -	$ -
	5	79	52	17,482	12,233	5,249
	10	37	95	30,777	26,097	4,680
	15	32	100	42,280	35,251	7,029
	20	32	100	53,420	45,759	9,958
	25	26	105	64,135	53,494	10,641
	30	24	107	74,265	62,392	11,873
Delaware	0	70	-	-	-	-
	5	51	19	6,416	2,473	3,944
	10	28	42	10,593	6,187	4,406
	15	25	45	13,664	7,590	6,074
	20	21	49	16,247	9,404	6,843
	25	19	51	18,637	10,557	8,080
	30	18	52	20,878	11,617	9,260
District of Columbia	0	35	-	-	-	-
	5	21	14	3,737	2,361	1,376
	10	10	25	5,777	4,418	1,359
	15	9	26	7,572	5,044	2,528
	20	9	26	9,266	6,199	3,067
	25	9	26	10,917	6,525	4,392
	30	9	26	12,528	7,793	4,735
Florida	0	318	-	-	-	-
	5	284	142	33,998	12,145	21,853
	10	129	296	54,528	35,153	19,375
	15	94	331	66,930	45,114	21,817
	20	72	353	75,727	53,356	22,371
	25	58	368	82,610	59,890	22,720
	30	54	372	88,965	63,215	25,750
Georgia	0	212	-	-	-	-
	5	127	85	15,428	6,836	8,592
	10	76	136	26,467	15,372	11,095
	15	56	156	34,310	21,682	12,628
	20	49	163	40,691	24,905	15,786
	25	32	181	45,418	33,236	12,182
	30	31	182	49,725	35,215	14,510
Hawaii	0	14	-	-	-	-
	5	14	0	1,377	0	1,377
	10	6	8	2,243	1,014	1,229
	15	2	12	2,694	1,995	699
	20	2	12	2,078	830	2,075
	25	2	12	3,116	2,078	1,038
	30	2	12	3,323	2,078	1,245

Table H.1. Projected State-by-State responses to a national tax on sulfur emissions (con.)

State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
Idaho	0	3	0	$ 0	$ 0	$ 0
	5	2	1	214	89	125
	10	1	2	324	154	170
	15	1	2	417	222	195
	20	1	2	500	221	279
	25	1	2	566	332	234
	30	1	2	624	550	74
Illinois	0	823	-	-	-	-
	5	402	421	68,796	46,436	24,361
	10	228	595	115,228	85,384	29,744
	15	218	609	154,442	104,833	49,608
	20	196	627	191,225	128,760	62,465
	25	172	651	225,668	155,884	69,784
	30	137	686	253,407	187,161	66,245
Indiana	0	901	-	-	-	-
	5	378	523	82,278	62,071	19,907
	10	256	644	139,086	119,511	33,359
	15	198	702	184,481	142,832	41,650
	20	172	728	224,521	173,594	50,926
	25	137	763	260,845	210,256	50,589
	30	131	770	292,003	231,529	60,474
Iowa	0	84	-	-	-	-
	5	55	29	7,066	3,216	3,850
	10	35	49	12,401	6,958	5,443
	15	25	59	16,721	10,573	6,148
	20	19	65	19,793	13,542	6,251
	25	18	66	22,513	15,078	7,435
	30	17	67	25,096	16,504	8,592
Kansas	0	45	-	-	-	-
	5	36	10	4,332	1,243	3,089
	10	32	14	10,148	2,566	5,815
	15	25	20	11,837	4,658	7,180
	20	24	21	14,891	5,688	9,202
	25	24	22	17,828	6,603	11,225
	30	24	22	20,728	7,234	13,494
Kentucky	0	633	-	-	-	-
	5	272	361	34,248	19,514	14,734
	10	157	476	75,820	39,843	18,734
	15	149	484	75,820	43,534	32,287
	20	135	498	92,135	50,789	41,346
	25	94	538	104,588	69,904	34,683
	30	53	579	112,863	93,697	19,166

Table H.1. Projected State-by-State responses to a national tax on sulfur emissions (con.)

State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
Louisiana	0	118	-	$ -	$ -	$ -
	5	108	10	11,085	441	10,645
	10	59	59	18,212	6,571	11,642
	15	55	63	23,871	7,592	16,279
	20	52	66	29,183	8,582	20,600
	25	51	66	34,360	8,740	25,621
	30	51	66	39,527	8,742	30,786
Maine	0	23	-	-	-	-
	5	14	9	2,072	1,151	921
	10	6	16	3,253	2,520	733
	15	5	16	4,111	2,827	1,284
	20	5	17	4,881	3,348	1,533
	25	4	17	5,573	3,719	1,854
	30	4	18	6,196	4,304	1,892
Maryland	0	318	-	-	-	-
	5	171	147	23,403	12,574	10,829
	10	104	215	40,709	26,245	14,464
	15	89	230	53,625	33,278	20,347
	20	72	247	63,976	41,579	22,397
	25	56	263	72,550	51,114	21,436
	30	49	269	80,127	56,759	23,368
Massachusetts	0	352	-	-	-	-
	5	170	181	26,651	16,644	10,007
	10	107	245	41,458	27,160	14,298
	15	75	277	52,370	37,011	15,359
	20	69	283	61,248	24,124	37,124
	25	55	297	69,091	48,711	20,380
	30	53	299	76,298	51,182	25,116
Michigan	0	779	-	-	-	-
	5	313	466	73,496	55,194	18,303
	10	187	591	120,400	95,981	24,420
	15	164	615	159,530	123,584	35,948
	20	122	657	192,488	156,595	35,893
	25	111	669	222,595	180,579	42,016
	30	108	672	250,965	474,297	76,666
Minnesota	0	248	-	-	-	-
	5	147	101	15,333	5,449	9,884
	10	77	170	26,079	15,416	10,663
	15	64	184	33,542	19,179	14,363
	20	56	192	40,117	22,847	17,270
	25	44	203	45,355	27,878	17,477
	30	36	212	50,122	33,722	16,399

Table H.1. Projected State-by-State responses to a national tax on sulfur emissions (con.)

State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
Mississippi	0	28	-	$ -	$ -	$ -
	5	20	7	2,071	370	1,701
	10	16	12	3,816	1,106	2,711
	15	15	13	5,302	1,236	4,066
	20	13	15	6,655	1,236	4,681
	25	13	15	7,890	2,115	5,775
	30	13	15	9,110	2,120	6,990
Missouri	0	318	-	-	-	-
	5	196	122	27,218	13,075	14,143
	10	117	201	46,084	28,261	17,824
	15	87	231	40,147	38,506	20,567
	20	74	244	70,037	45,698	24,339
	25	51	267	78,376	58,425	19,951
	30	46	272	85,442	63,523	21,919
Montana	0	303	-	-	-	-
	5	38	268	18,509	14,842	3,369
	10	35	270	22,221	14,935	7,207
	15	35	271	25,771	15,509	10,261
	20	31	275	29,027	16,884	12,148
	25	31	275	32,066	17,059	15,007
	30	31	275	35,093	17,059	18,034
Nebraska	0	133	-	-	-	-
	5	24	109	5,682	4,071	1,610
	10	16	117	7,649	5,228	2,421
	15	12	121	9,144	6,302	2,842
	20	9	124	10,306	7,267	3,038
	25	9	124	11,374	7,749	3,625
	30	8	125	12,384	8,156	4,228
Nevada	0	117	-	-	-	-
	5	17	100	6,654	5,433	1,222
	10	12	105	8,474	6,568	1,906
	15	12	105	9,956	6,866	3,091
	20	11	106	11,382	7,557	3,826
	25	9	108	12,632	5,606	2,637
	30	9	108	13,819	8,943	4,876
New Hampshire	0	84	-	-	-	-
	5	54	31	5,542	1,932	3,610
	10	29	56	9,649	5,524	4,125
	15	20	65	12,072	7,737	4,335
	20	17	68	13,910	8,853	5,057
	25	11	73	15,363	11,245	4,110
	30	11	73	16,628	11,409	5,219

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State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
New Jersey	0	354	-	$ -	$ -	$ -
	5	209	145	32,249	17,339	14,910
	10	123	231	52,500	33,755	18,745
	15	104	250	67,330	41,901	25,430
	20	88	266	79,780	50,247	29,533
	25	82	272	90,570	55,558	35,012
	30	70	284	100,030	63,840	36,191
New Mexico	0	305	-	-	-	-
	5	150	256	30,135	21,082	9,053
	10	111	295	46,852	30,403	16,452
	15	75	330	58,112	41,300	16,812
	20	64	331	67,495	83,786	19,908
	25	34	371	74,200	62,818	11,381
	30	32	373	79,632	65,855	13,776
New York	0	671	-	-	-	-
	5	318	353	57,955	39,053	18,903
	10	197	474	91,751	71,111	26,640
	15	171	500	119,748	81,228	38,520
	20	155	516	144,515	95,310	49,205
	25	127	545	166,082	115,371	50,711
	30	123	549	185,769	124,902	60,867
North Carolina	0	1,656	-	-	-	-
	5	636	1,020	686	108,572	234
	10	270	1,186	235,974	175,168	60,806
	15	260	1,396	297,306	252,561	44,745
	20	251	1,405	346,194	279,036	67,158
	25	129	1,527	372,430	341,036	31,454
	30	123	1,533	396,268	352,373	40,895
North Dakota	0	54	-	-	-	-
	5	39	16	3,861	1,044	2,817
	10	27	27	7,088	2,893	3,985
	15	21	33	9,420	4,154	5,266
	20	17	37	11,265	5,435	5,830
	25	15	40	12,713	6,989	5,724
	30	14	40	14,057	7,075	6,982
Ohio	0	1,172	-	-	-	-
	5	699	473	112,033	64,943	47,090
	10	392	780	187,572	132,062	55,510
	15	276	896	241,353	181,590	59,763
	20	241	931	288,813	215,586	73,227
	25	204	968	331,615	252,637	78,978
	30	193	979	370,038	277,584	92,454

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State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
Oklahoma	0	72	-	$ -	$ -	$ -
	5	24	48	4,035	2,010	2,337
	10	21	50	6,311	2,221	4,400
	15	20	52	8,400	2,596	11,382
	20	19	53	10,319	2,947	7,373
	25	19	54	12,170	3,152	9,018
	30	17	54	13,992	3,202	10,791
Oregon	0	3	-	-	-	-
	5	2	1	280	131	149
	10	1	2	405	222	149
	15	1	2	509	237	238
	20	1	2	606	245	327
	25	1	2	704	244	426
	30	1	2	795	280	481
Pennsylvania	0	1,482	-	-	-	-
	5	707	775	139,875	97,959	41,915
	10	420	1,062	228,005	172,716	55,288
	15	346	1,136	291,985	216,984	75,001
	20	280	1,202	346,884	263,623	83,261
	25	234	1,248	395,205	306,864	88,341
	30	215	1,267	438,083	337,766	100,318
Rhode Island	0	24	-	-	-	-
	5	12	12	2,224	1,462	762
	10	7	12	3,168	2,285	883
	15	7	17	4,033	2,605	1,429
	20	7	17	4,826	2,805	2,021
	25	6	18	5,582	3,152	2,430
	30	6	18	6,292	3,281	3,011
South Carolina	0	306	-	-	-	-
	5	148	158	27,337	18,708	8,629
	10	83	223	45,109	34,569	10,540
	15	66	240	56,824	43,376	13,448
	20	59	247	67,097	49,884	17,213
	25	53	253	76,207	55,723	20,484
	30	38	268	82,836	65,837	16,999
South Dakota	0	13	-	-	-	-
	5	9	4	954	340	614
	10	6	7	1,649	690	959
	15	6	7	2,218	861	1,357
	20	4	9	2,676	1,351	1,325
	25	4	9	3,092	1,471	1,621
	30	4	9	3,492	1,496	1,996

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State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
Tennessee	0	220	-	$ -	$ -	$ -
	5	192	34	17,811	2,886	14,925
	10	142	83	33,201	8,888	24,989
	15	140	86	47,200	9,784	37,416
	20	137	89	60,982	10,576	37,416
	25	136	90	74,612	10,841	63,766
	30	47	178	84,178	60,506	23,672
Texas	0	305	-	-	-	-
	5	181	125	23,897	6,184	17,713
	10	150	156	40,077	10,629	29,448
	15	137	168	54,249	13,551	40,697
	20	134	171	67,700	14,751	52,949
	25	133	172	80,994	14,978	66,015
	30	132	183	94,201	15,375	78,819
Utah	0	34	-	-	-	-
	5	33	0	2,869	131	2,738
	10	17	17	5,251	239	2,950
	15	17	17	7,002	346	4,594
	20	14	20	8,499	3,666	4,833
	25	12	22	9,666	4,450	5,216
	30	11	23	10,730	5,140	5,590
Vermont	0	5	-	-	-	-
	5	2	2	298	153	145
	10	1	3	450	292	158
	15	1	4	583	337	246
	20	1	4	699	366	333
	25	1	4	800	387	413
	30	1	4	891	511	380
Virginia	0	213	-	-	-	-
	5	119	94	19,876	12,046	7,829
	10	74	151	47,547	30,179	15,104
	15	63	151	47,547	30,179	15,104
	20	55	159	58,308	40,132	18,176
	25	45	169	66,849	48,368	18,581
	30	41	193	74,124	53,640	20,483
Washington	0	120	-	-	-	-
	5	55	65	7,606	2,433	5,172
	10	21	98	10,300	6,027	4,055
	15	17	102	12,294	7,006	5,098
	20	17	102	14,110	7,209	7,001
	25	17	103	15,921	7,270	8,651
	30	17	103	17,712	7,377	10,335

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State	Tax rate (cents per pound of sulfur emissions)	Emissions (thousand tons)	Reductions in emissions from zero tax (thousand tons)	Total annual cost (thousands)	Annualized control costs (thousands)	Annual tax payment (thousands)
West Virginia	0	558	-	$ -	$ -	$
	5	249	309	34,520	20,764	13,756
	10	147	410	59,143	40,688	18,455
	15	132	426	75,361	46,825	28,536
	20	124	434	90,032	51,318	38,715
	25	79	479	102,197	73,544	28,654
	30	55	503	110,057	87,816	22,242
Wisconsin	0	383	-	-	-	-
	5	189	194	27,738	16,468	11,270
	10	101	282	45,874	33,416	12,458
	15	84	300	58,415	41,185	17,230
	20	72	312	69,119	47,855	21,165
	25	55	329	78,690	59,020	19,670
	30	49	335	86,339	64,610	21,729
Wyoming	0	78	-	-	-	-
	5	57	22	7,232	242	5,650
	10	37	42	12,510	1,541	7,137
	15	30	57	15,351	2,648	8,969
	20	31	51	18,332	2,923	11,212
	25	22	58	20,849	2,941	10,275
	30	20	59	22,929	3,333	11,563

Source: Research Triangle Institute.